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MANAGEMENT CONSULTANTS

ENERGY INDUSTRY UPDATE

# MONEY, MONEY, MONEY

Volume 22 - Issue 2

# CONTENTS

# EXECUTIVE SUMMARY
## Money, Money, Money

This Energy Industry Update examines how energy infrastructure investment needs continue to grow, while post-pandemic and geopolitical trends keep inflation a topic of intense discussion. This has focused the attention of energy policymakers, industry participants, and stakeholders on capital as well as operating and maintenance costs required for the sector. Specifically: Where is this funding coming from? How much is needed? How will it be recovered or repaid?

| Some Highlights of This ScottMadden Energy Industry Update | |
|---|---|
| **Where is the money coming from?** | ▪ Less than a year after passing major federal infrastructure legislation, Congress has passed $369 billion+ legislation containing energy- and climate-related incentives and investments. Much work lies ahead in organizing and deploying programs under the Inflation Reduction Act of 2022, while energy companies consider which investments will be most beneficial to their respective businesses. |
| **Where is the money being deployed?** | ▪ Numerous utilities are deploying grid modernization programs to update grid facilities, enhance demand response and efficiency, facilitate distributed resource deployment, and prepare for increased electrification. But end-user behavior, such as widespread vehicle electrification, remain years away. How do you plan, develop, and recover investment in a grid that can accommodate a distributed future?<br>▪ California began its energy transition decades ago and has recently accelerated its net-zero target to 2045. But as investment in resources, reliability, and the grid (both distribution and transmission) have been made and more are contemplated, hurdles remain to deal with fire and hydrological conditions, import dependence, and rising costs. California's journey has potential lessons for other jurisdictions seeking to transform their respective energy sectors.<br>▪ Post-pandemic recovery has led to increasing natural gas demand, and supply has been working to keep up. But the sector now faces factors, such as effects of geopolitical events and policy, and historically low prices have turned upward in recent months. Meanwhile, continued gas-power interdependence for electric reliability underscores the continuing need for adequate and reasonably priced gas supplies for the foreseeable future. Are these dynamics transitory or long-lived? |
| **How will costs be recovered?** | ▪ The past several years have seen rising generation fuel prices, growing investment in electric infrastructure, and continued build-out of low-carbon-emitting resources. We expect many utilities to grow their investments as they pursue net-zero objectives. As these costs eventually work their way into rates, utilities and regulators must consider the trajectory of energy costs and their impact on affordability. |

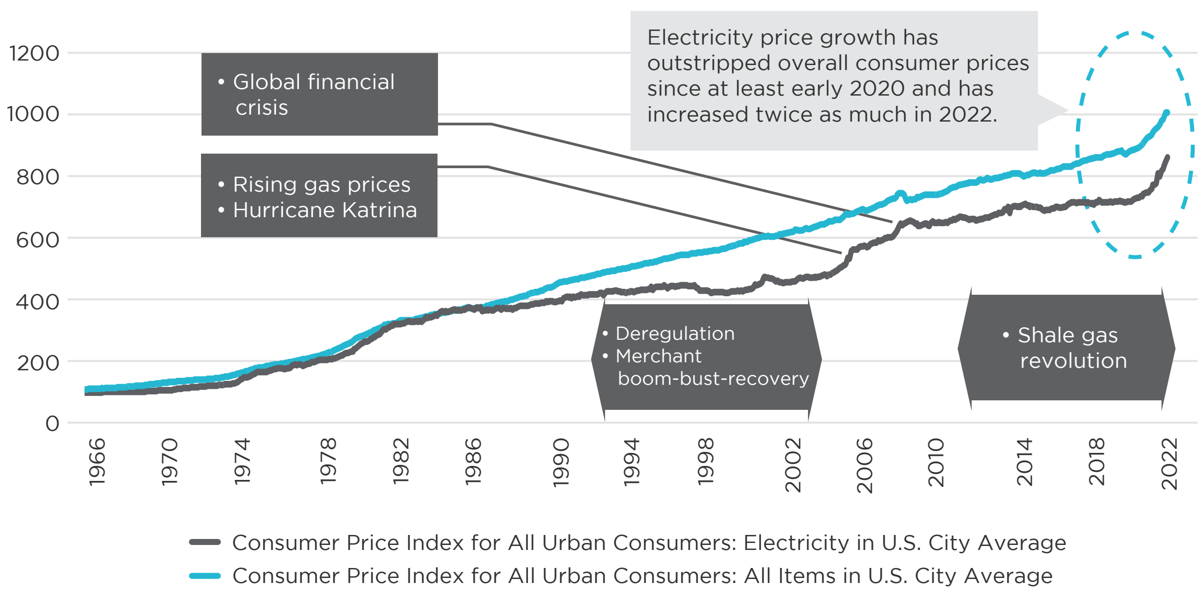
## Energy Cost and Affordability: Watching Trends

As macro trends alter the energy landscape and significant investments in energy transition are contemplated, focus turns to maintaining affordability.

## A Historical Trend of Good News

- Over the past decade, energy costs have generally been stable or declining, in sympathy with broader trends. From 2012 to 2021, the U.S. average cost of electricity increased by less than 1% per year, compared with the broader consumer inflation rate of just under 2% annually.
- While utilities have grown capital investment in utility infrastructure, increases in utility rates and bills have generally been modest because of several structural factors:
  - Low-fuel (especially natural gas) costs for power generation
  - Increased competition
  - Consolidation (with scale economies)
  - Lower Treasury rates (and hence lower required returns on equity)
  - Generally lower commodity costs

Figure 1.1: **Total Consumer Price Index vs. Electric Consumer Price Index (Monthly) (Index: Jan. 1960=100)**




**Source:** Federal Reserve Bank of St. Louis

## KEY TAKEAWAYS

**A long trend of lower electricity costs, tied to low natural gas prices, has reached an inflection point. To date, low natural gas costs have tempered rate increases even as utilities have continued to invest in their systems.**

**Looking ahead, increasing grid investments and incremental spend to reach net-zero objectives will require significant investments, but utilities and regulators will need to balance variables of net-zero, reliability and resilience, and energy affordability.**

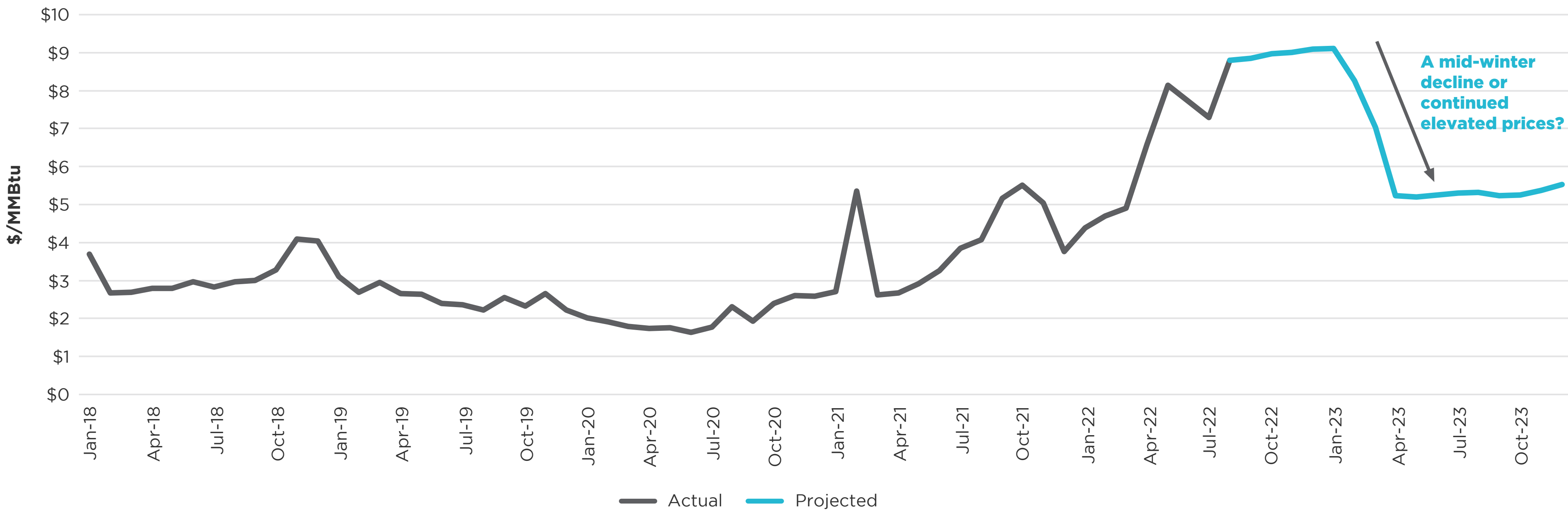
**Policymakers, regulators, and utilities may be faced with difficult trade-offs as they weigh reliability requirements, clean energy targets, and customer affordability.**

**The IRA could help temper rate increases and reduce energy costs for consumers adopting energy efficiency measures, but it is too early to tell how and whom it will assist.**

## Transitory Period or End of an Era?

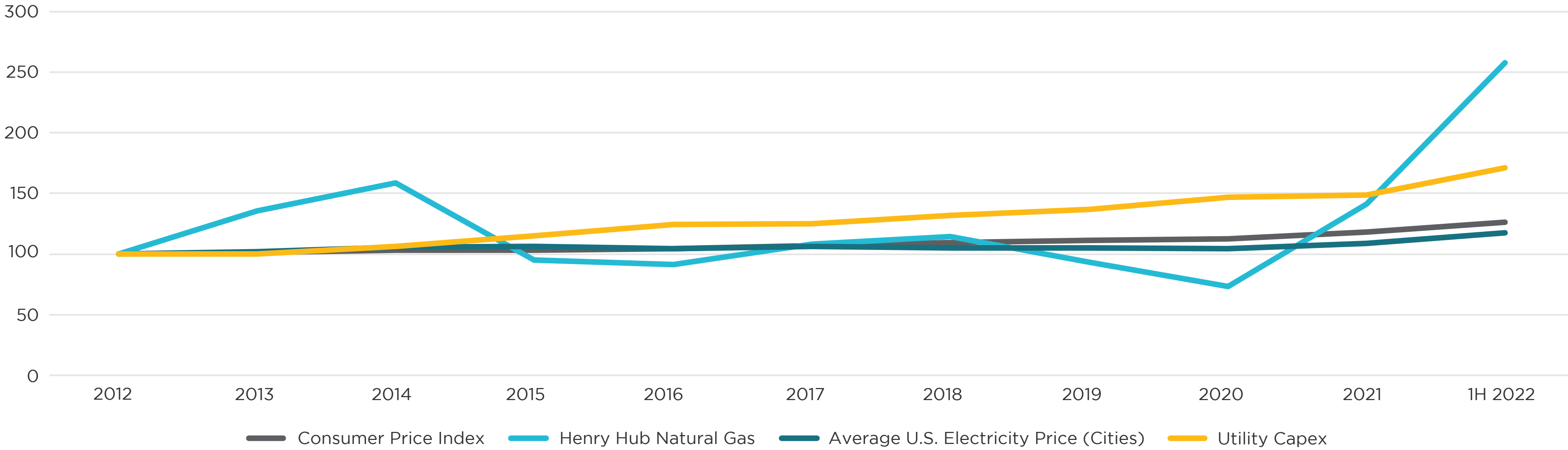
- Beginning in mid-2020, however, natural gas and other commodity prices began trending upward, sometimes at a significant rate. Natural gas has risen from under $2/MMBtu in 2020 to nearly $10/MMBtu in 2022. This increase has come because of multiple factors, including warm weather leading to higher gas demand for power generation and lower than usual gas inventories. While too early to tell its potential effects, increased global LNG demand may also impact domestic gas prices (most certainly in New England).
- In addition, commodities necessary for batteries, most notably lithium, as well as other key electric infrastructure metals such as copper, have seen price increases due to several factors, including geopolitical events, supply chain issues, and growing demand. In fact, the price of lithium increased more than 700% from the beginning of 2021 to the summer of 2022.
- The question for regulators and utilities, as well as policymakers, is whether these cost trends are transitory (a word that has inspired much debate of late) or part of a broader, more long-lasting trend of generalized inflation.

Figure 1.2: **Actual and EIA Forecasted Henry Hub Monthly Natural Gas Prices ($/MMBtu) (Jan. 2018–Dec. 2023)**




**Source:** EIA

Figure 1.3: **Change in Key Prices and Selected Utility Capital Expenditures (2012–Present) (Index: 2012=100)**




**Sources:** Federal Reserve Bank of St. Louis; Edison Electric Institute

## Downstream Impacts on Electricity Costs?

- Over the past decade, utility capex, and more recently natural gas prices, have increased at a greater pace than the Consumer Price Index and average U.S. electricity prices. And while many utilities have fuel cost hedges to limit their exposure to large price increases, as those hedges expire, utilities may be rolling over hedges at higher price levels.
- In 2020, however, at the same time natural gas prices began to spike, inflation and electricity prices started to rise. This is being reflected in growing rate increase requests.
- Even as these trends are driving electricity cost increases, electric utilities are planning—and in some cases mandated—to significantly grow investment in all elements of the electricity value chain as part of energy transition, such as:
  - **Distribution:** Accommodating building and vehicle electrification, modernizing the grid, adding storage and other non-wires alternatives, and expanding efficiency and demand response programs
  - **Transmission and system operations:** Expanding regional footprints, interconnecting renewables, replacing aging infrastructure, resilience investments, load growth in growing regions, electrification, and flexible resource procurement to ensure resource and energy adequacy
  - **Generation:** Adding new resources, both dispatchable and variable and emitting and non-emitting; increasing gas interconnections; and piloting new technologies (hydrogen, advanced nuclear, carbon capture, utilization, and storage)

## Downstream Impacts on Electricity Costs? (Cont.)

- Cost and investment estimates for net zero vary depending upon scenario and assumption and the blend of potential investments noted above. For example, Princeton's 2020 *Net Zero America* report estimates that a system with aggressive end-use electrification and 100% renewables will require the following electric capital investment to meet a 2050 net-zero goal:
  - **Distribution:** $370 billion in the 2020s and $700 billion per decade in the 2030s and 2040s
  - **Transmission:** $2.4 trillion of high-voltage capacity through 2050
  - **Solar/wind:** $3.2 trillion of solar and wind capacity through 2050
- Of course, not all of those costs are net-zero-related capital; significant amounts are for anticipated infrastructure spending regardless of net-zero investments. For context, net property, plant, and equipment of electric investor-owned utilities at year-end 2021 were about $1.36 trillion. Even assuming that the *Net Zero America* estimate is a high case, the amount of capex for the utility industry will be substantial over the next decade or more.

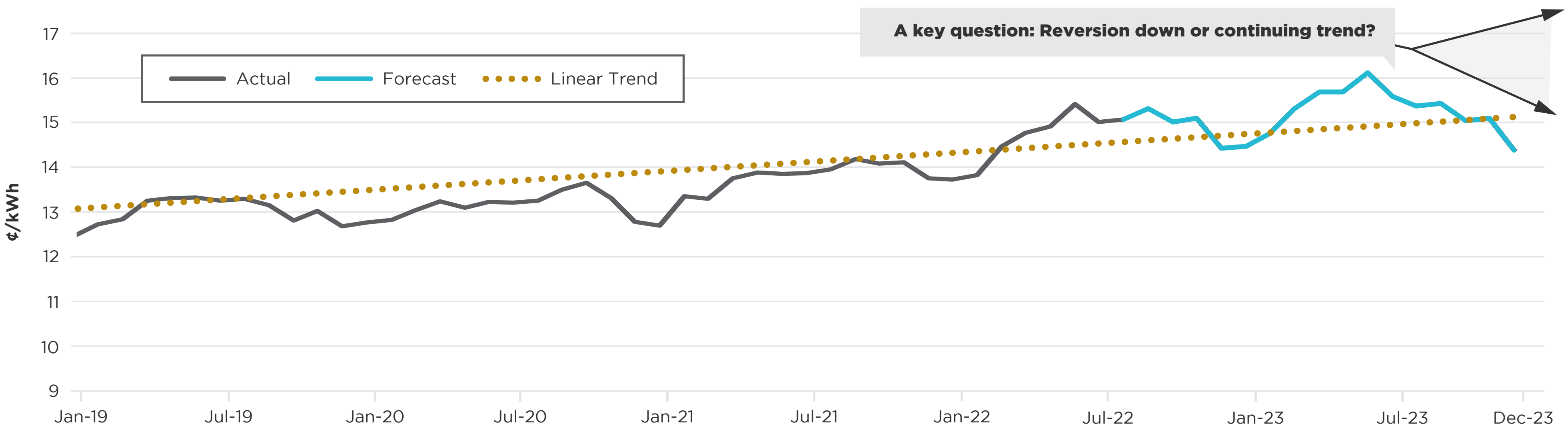
### How Much Might Costs Increase? Assumptions Matter

**Dominion Energy's recent integrated resource plan (IRP) update highlights how different assumptions can drive different expectations for customer bill increases. Dominion is planning for net zero by 2050 in accordance with the Virginia Clean Economy Act of 2020. It filed an IRP in 2020 and updated it as required by Virginia's State Corporation Commission (SCC) (its public utilities commission). For the company's affordability analysis, it used SCC-required assumptions with zero sales growth and current three-year solar capacity factors for company facilities.**

**Using the SCC assumptions, Dominion calculated a 4.5% CAGR in residential customer bills from May 2020–2030 and a 4.0% CAGR when extending the outlook to 2035, leading to a $97/month bill increase over the 2020–2035 time period. For reference, a typical Dominion monthly residential bill in May 2020 was $116.**

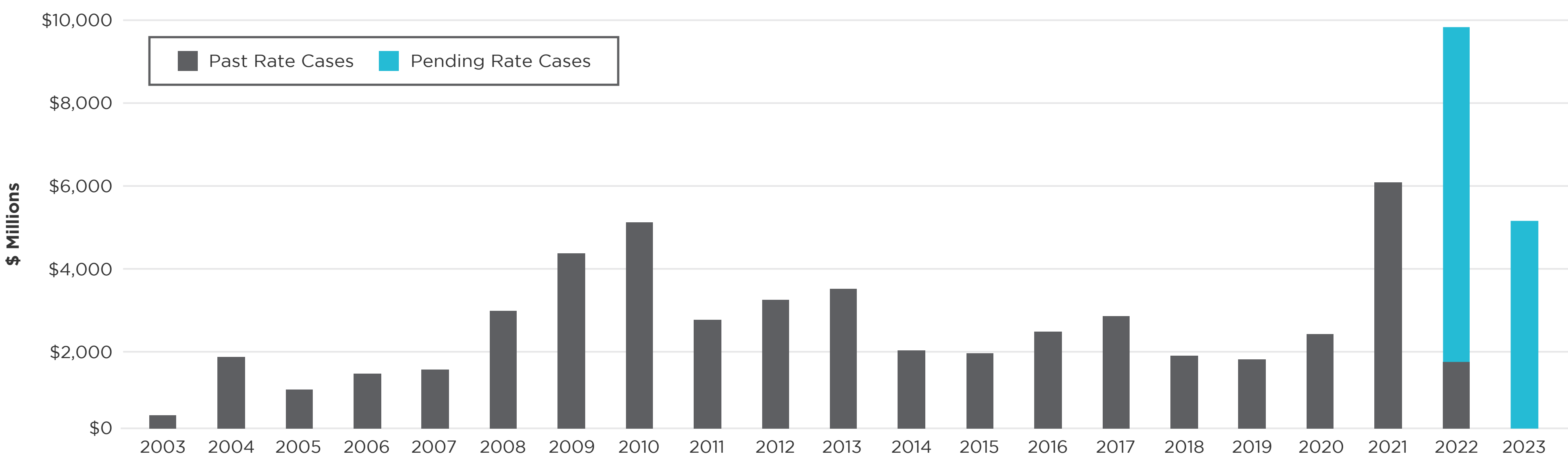
**Dominion believes these assumptions overstate the expected bill increases. Using its own methodology—system sales growth and design capacity factor for future resources—Dominion projects a 3.4% CAGR in customer bills from 2020–2030 and 2.7% through 2035, leading to a $61/month bill increase over the 2020–2035 time period.**

Figure 1.4: **Monthly Historical and Short-Term Forecast Average U.S. Residential Electricity Price (¢/kWh)**




**Source:** EIA

Figure 1.5: **Past and Pending U.S. Electric Utility Rate Increases by Year (2003-2023) ($ Millions)**




**Source:** S&P Global Market Intelligence-Regulatory Research Associates

Figure 1.6: **Electricity Price Increases: Potential Short- and Long-Term Drivers**

| Short- to Medium-Term (Up to 5 Years) | Long-Term (5 Years +) | Wild Card |
|---|---|---|
| **Tax credits** Provisions of the Inflation Reduction Act of 2022 (IRA), such as production tax credits, will help lower costs for energy providers, leading to energy user price reductions compared to pre-IRA forecasts. | **Geopolitics** Notably, the war in Ukraine has led to sanctions cutting off the trade of key commodities from Russia. | **Electrification** Investment in electrification will be costly, but it will lead to long-term savings, leaving its influence on prices unclear. |
| **Recession** A recession would work to significantly cut demand for many energy products and projects, possibly leading to a price decline in the near term. | **Inflation** Rising energy costs have been a large part of the current inflation rates, which are at highs not seen since the 1980s. | **Demand response** Demand response programs require investment in smart grids, and it is uncertain over what timeframe and to what degree these programs will provide savings. |
| **Loan programs** Taxpayer money will help to fund and reduce the cost of climate-friendly technologies, driving costs down. | **New costs in IRA** The IRA will raise costs for some industries through its imposed methane emissions fee and an increase on royalties for oil and gas leases. | |
| **Permitting reform** Current energy permitting structures are remarkably inefficient. If permitting reform is enacted, it could facilitate the development of projects, which will help cut costs in the near term. | **Supply chain** COVID-19 and global conflict have led to worldwide supply chain issues; however, a large problem in the current outlook stems from the scarcity of resources key to the energy transition and lack of development in their supply chains. | |

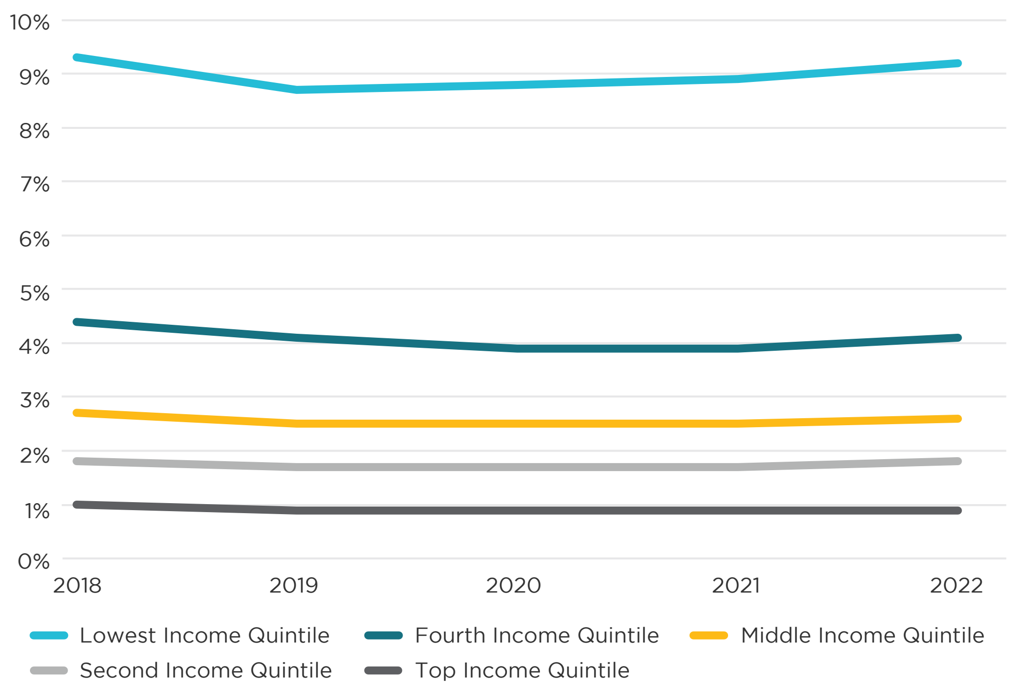
**Source:** ScottMadden analysis

## Growing Emphasis on Affordability

- As utility costs and prices trend upward, regulators, utilities, and stakeholders are refocusing attention on affordability. That issue garnered attention during the COVID-19 pandemic when stay-at-home orders caused job dislocations and related income reductions affecting some customers' ability to pay utility bills. Now, despite economic recovery, across-the-board consumer costs are affecting energy affordability.
- To date, aggregate energy burden—the percentage of household income spent on energy expenditures—has remained modest overall. According to the American Council for an Energy-Efficient Economy, as of 2017, U.S. households spent an average of 3.1% of income on home energy bills. Looking by groups, however, reveals significant differences by income and other categories (see Figure 1.7 at right). Recent electricity price spikes are gaining broader attention, as a recent survey found that 20 million American homes had fallen behind on their utility bills.
- Affordability is defined differently from jurisdiction to jurisdiction and sometimes not consistently across regulatory proceedings. For instance, only relatively recently (summer 2020), California adopted metrics by which it would assess relative affordability of essential utility service across its proceedings. The California Public Utilities Commission (CPUC) has also produced an annual affordability report (beginning in 2021) in which it gauges utility bills (power, gas, water, and telecom) against three metrics (see Figure 1.8):
  - Affordability ratio (for households in the 20th income percentile)
  - Hours at minimum wage
  - Impacts on disadvantaged communities

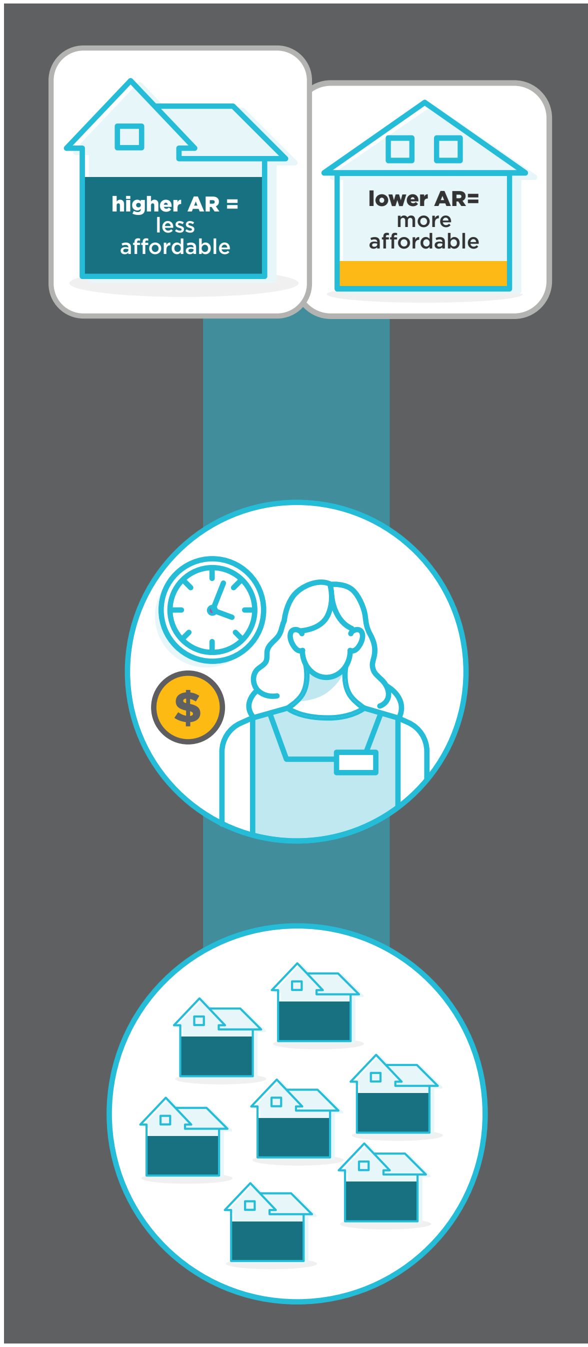
  Because these reports are relatively new, California has limited trending information. But its latest published report notes that more than 13% of households were in areas where electric affordability ratios for the 20th percentile income were above 15%, which is an indicator of unaffordability.
- Many regulators and utilities will monitor affordability in their rate proceedings, focusing on the impact of increased spending on all customers, with a view toward geographic areas and customer segments more significantly affected by increasing bills. These findings could lead to actions on implementation and effectiveness of low-income energy efficiency, energy assistance, and alternate rate programs.

Figure 1.7: **U.S. Household Percentage of Income Spent on Electricity by Income Tier (2018–20 Actual and 2021–22 Estimated)**




**Source:** National Energy Assistance Directors Ass'n

Figure 1.8: **California's Recently Implemented Approach to Affordability Metrics**




**Affordability Ratio (AR)**

$ **essential services bill**

$ **household income – non-discretionary expenses (housing and other utilities)**

= **AR**

*where utility services are least affordable for households at a particular point of the income distribution (e.g., $AR_{20}$ is households at the lowest 20th percentile of income)*

**The Affordability Ratio (AR)** quantifies the percentage of a representative household's income that would be used to pay for an essential utility service, after non-discretionary expenses such as housing and other essential utility service charges are deducted from the household's income.

The higher an AR the less affordable the utility service. The AR may be calculated for a single essential utility service, a combination of services, or all essential utility services combined. To better understand how essential utility service charges impact lower-income households, the proceeding specifically examines $AR_{20}$, which represents the household with income at the 20th percentile in a given geography.

**Hours at Minimum Wage (HM)**

# **Hours of earned employment at the local minimum wage needed to pay for essential services**

= **HM** *where low-income households will have the most difficulty paying for essential services, regardless of the socioeconomic condition of the neighbors*

**The Hours at Minimum Wage** quantifies the hours of earned employment at the city's minimum wage necessary for a household to pay for essential utility service charges. The minimum wage-based metric also implicitly considers the impact of essential utility service charges on lower-income customers regardless of the socioeconomic conditions of the community as a whole.

**CalEnviroScreen (CES)**

**Relative standing of community (census tract) based on:**

- population characteristics
- pollution burden

= **CES** *identifies communities least able to afford increases in charges for essential services*

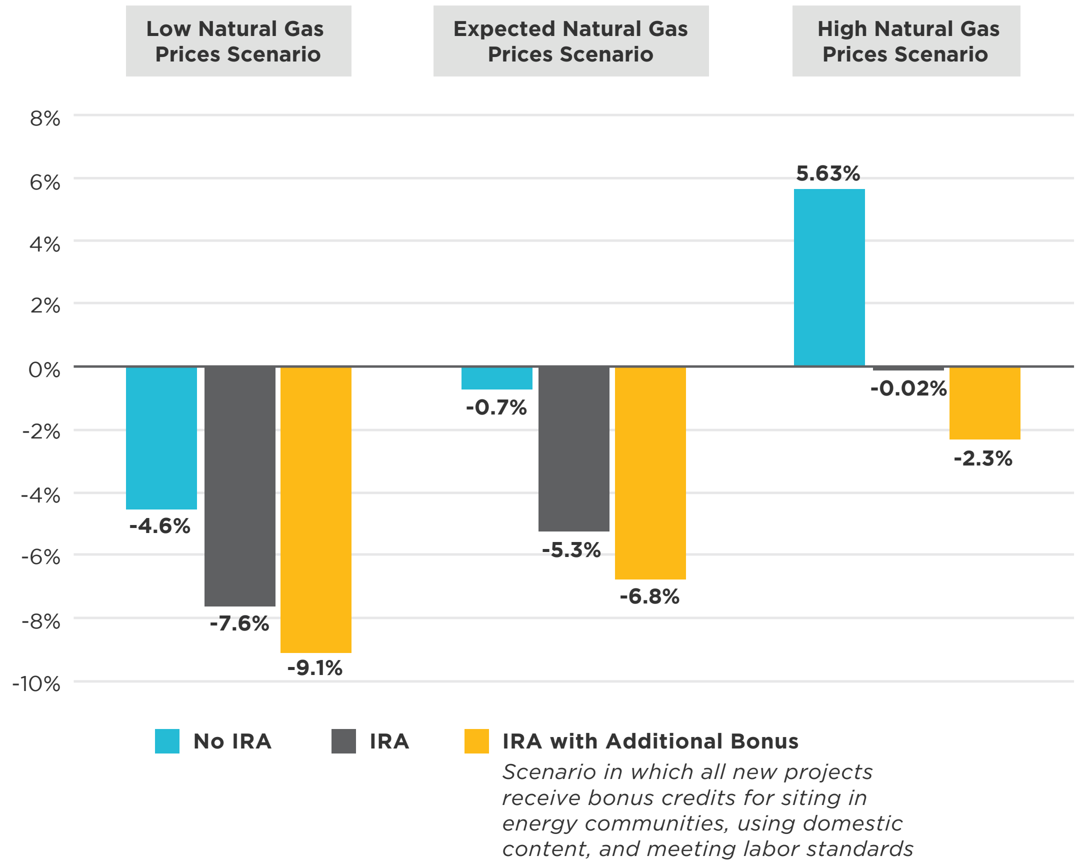
**The CalEnviroScreen (CES) metric** represents a metric that is independent of utility bill data and is comprised of 21 population characteristics and pollution burden indicators. Each census tract has a composite CES score imputed from the 21 indicators, with higher scores representing communities that are more negatively impacted.

**Source:** CPUC

## To the Rescue?—
## Potential Impacts of Inflation Reduction Act

- In August, Congress passed and the President signed the IRA. The legislation includes $369 billion in investments and incentives designed to significantly lower the cost to manufacture and deploy zero-carbon technologies, energy efficiency measures, and building electrification.
- The legislation contains provisions for production and investment tax credits for clean energy projects. The effect of the tax credits and government investment assistance in clean energy and related transmission and distribution infrastructure could reduce revenue requirements for utilities, which would be transmitted to customers via lower rates.
- One early analysis of the IRA assumes that non-carbon-emitting energy investment will shield electricity customers from natural gas price volatility and perhaps reduce gas prices, leading to lower bills (see adjacent Figure 1.9).
  - The IRA is expected to save electricity consumers between $209 billion and $278 billion from 2023–2032, as that analysis posits that electricity prices will decline between 5.2% and 6.7%.
  - Over the decade, the analysis projects annual savings of $170 to $220 on electricity bills for the average U.S. household.
- The IRA also provides incentives for energy efficiency and electrification that may offer substantial energy savings to end consumers.
- It is unclear and still early to determine whether these interactions between government incentives, utility investment requirements, and fuel (specifically natural gas) prices will work to reduce rates. Utilities and policymakers will watch this closely.

Figure 1.9: **Projected Change in Average Retail Electricity Prices (2023–2032) With and Without Inflation Reduction Act of 2022**




**Source:** Resources for the Future

## Considerations for Utilities

- As utilities contend with increasing investment requirements and, for now, higher natural gas, commodity, and labor costs, they will need to consider some key questions:
  - Will electrification hit a cost “wall” as investments increase substantially beyond historical replace and upgrade cycles?
  - Will increasing rates and/or bills cause customers to push back on energy transition investments, questioning their cost effectiveness?
  - Will the utility industry revisit its “death spiral” fears from a decade ago as higher rates incentivize distributed energy resources?
  - What are the implications of cost allocation to customers for increasing spend, particularly as it affects moderate- and low-income customers?
  - What are implications for rate design, as systems introduce more fixed, non-volumetric costs (grid enhancement, reliability investment) together with zero-marginal cost renewable resources and increasing levels of energy efficiency?

## IMPLICATIONS

**Utilities must balance affordability, reliability, and clean energy in providing electricity service to their customers. It is unclear whether the elevated inflation rate seen in electricity costs will be persistent and long-lasting.**

**But as energy transition costs grow, utilities and their regulators will be well-served to consider ways to temper rate hikes, enhance programs that assist in ensuring energy affordability (including special rates, payment assistance, and efficiency), and tailor rate designs to higher fixed system costs.**

**Notes:**

In Figure 1.3, 2022 utility capex is a projection for the year as of June 2022. 2022 data points for CPI, Henry Hub, and the average electricity price are prices as of the first half of 2022. Average electricity prices are consumer averages for U.S. cities. Utility capex represents total company spending of U.S. investor-owned electric utilities; 2022 is projected through the end of 2022.

In Figure 1.5, data as of Sept. 13, 2022. Regulatory Research Associates only covers rate cases in which the company has requested a rate change of at least $5 million or has authorized a rate change of at least $3 million.

**Sources:**

“Inflation rearing its head in electric, gas general rate cases nationwide,” S&P Global Market Intelligence (Sept. 7, 2022); “2022 energy, water utility capex plans on track for record-breaking year,” S&P Global Market Intelligence (Apr. 12, 2022); Princeton University, Net Zero America: Potential Pathways, Infrastructure, and Impacts (Dec. 15, 2020) (interim report); EEI, 2021 Financial Review (June 2022); 2022 Update to the 2020 Integrated Resource Plan of Virginia Electric and Power Company, as filed with the Virginia State Corporation Commission (Sept. 1, 2022), Case No. PUR-2022-00147, at para. 2.5; American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? (Sept. 2020); National Energy Assistance Directors Association, “NEADA Summer Electricity Outlook” (June 17, 2022); “A ‘Tsunami of Shutoffs’: 20 Million U.S. Homes Are Behind on Energy Bills,” Bloomberg (Aug. 23, 2022); California Public Utilities Commission, 2019 Annual Affordability Report (Apr. 2021); Resources for the Future, “Retail Electricity Rates Under the Inflation Reduction Act of 2022” (August 2022).

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The list below is a sample of recent insights prepared by our consultants.

**CASE STUDY**
**Racing to Net-Zero**

**ENERGY CENTRAL ARTICLE**
**Emerging Cost and Affordability Challenges in Time of Transition**

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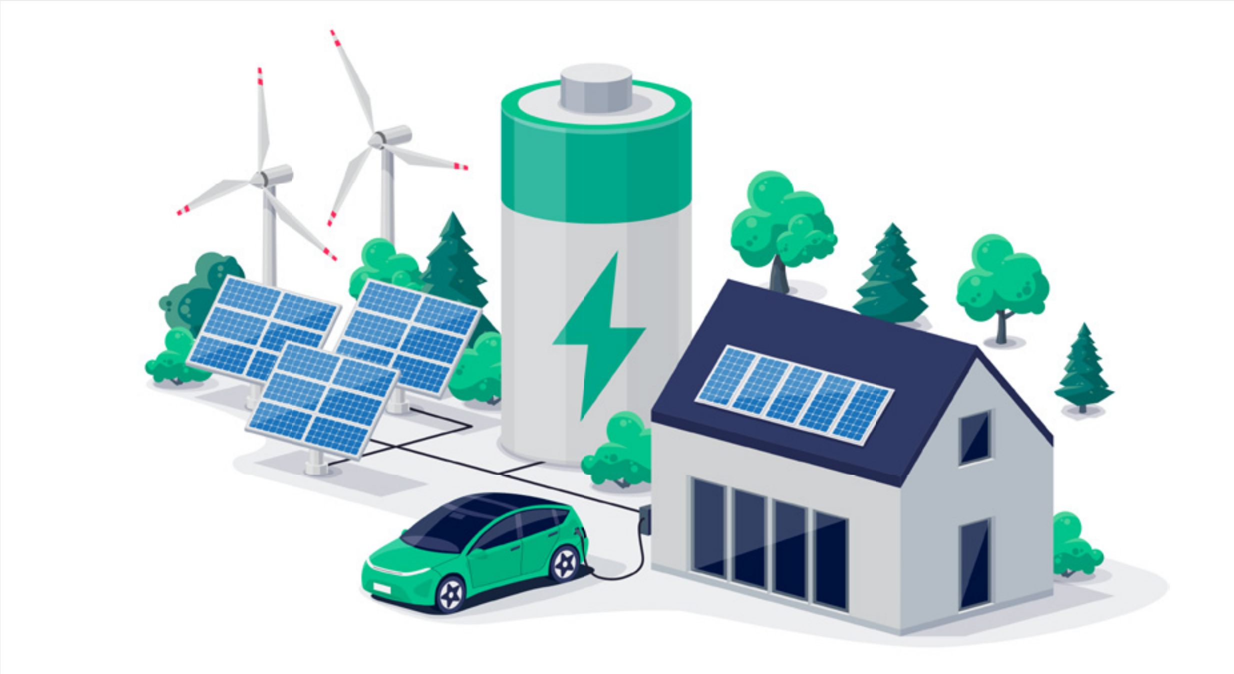
# Distributed Resources and Electrification Drive a Planning Rethink

Integrated distribution planning gains traction as more states consider grid needs given electrification, clean energy, and environmental justice.

## Distribution Investment Continues Apace

- Transmission and distribution (T&D) investment has been growing steadily for at least a decade and is expected to comprise the most significant portion of utility capital spending over the next two years.
- Still more investment is expected over the next decade. Key drivers include:
  - Replacements and upgrades of well-depreciated T&D facilities for safety, reliability, and resilience and to incorporate new and improved technologies
  - Electrification, as some utilities and jurisdictions (including federal policy) encourage electrification of transportation and heating and cooking applications
  - Growth in distributed energy resources (DERs), given lower costs of photovoltaic solar, and policy support for non-carbon-emitting resources such as demand response and storage
- With this increased distribution investment, a growing number of states are requiring longer-term planning that accounts for these growing DERs and evolving policy priorities, including decarbonization and environmental and energy justice.



**Note:** DERs can be defined to include energy efficiency, demand response, distributed generation, combined heat and power, electric vehicles, and energy storage.

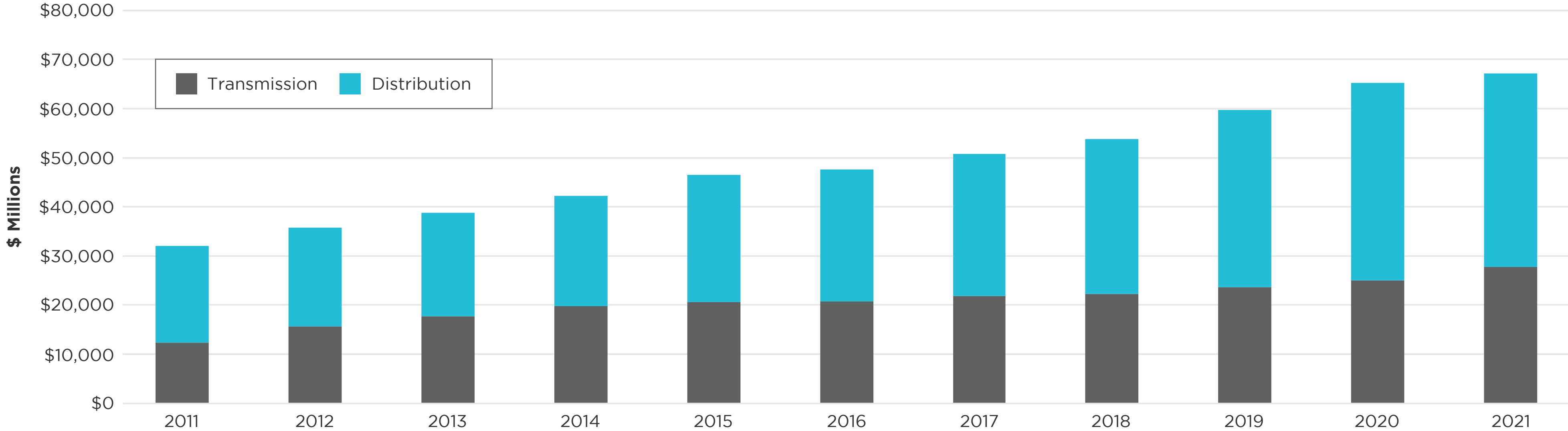
### KEY TAKEAWAYS

**Electric distribution investment is growing, driven by replacement of aging infrastructure, electrification, and promotion of distributed energy resources.**

**To guide investment and achieve certain policy goals, such as incentivizing non-carbon-emitting resources on the grid, regulators are setting expanded objectives for planning.**

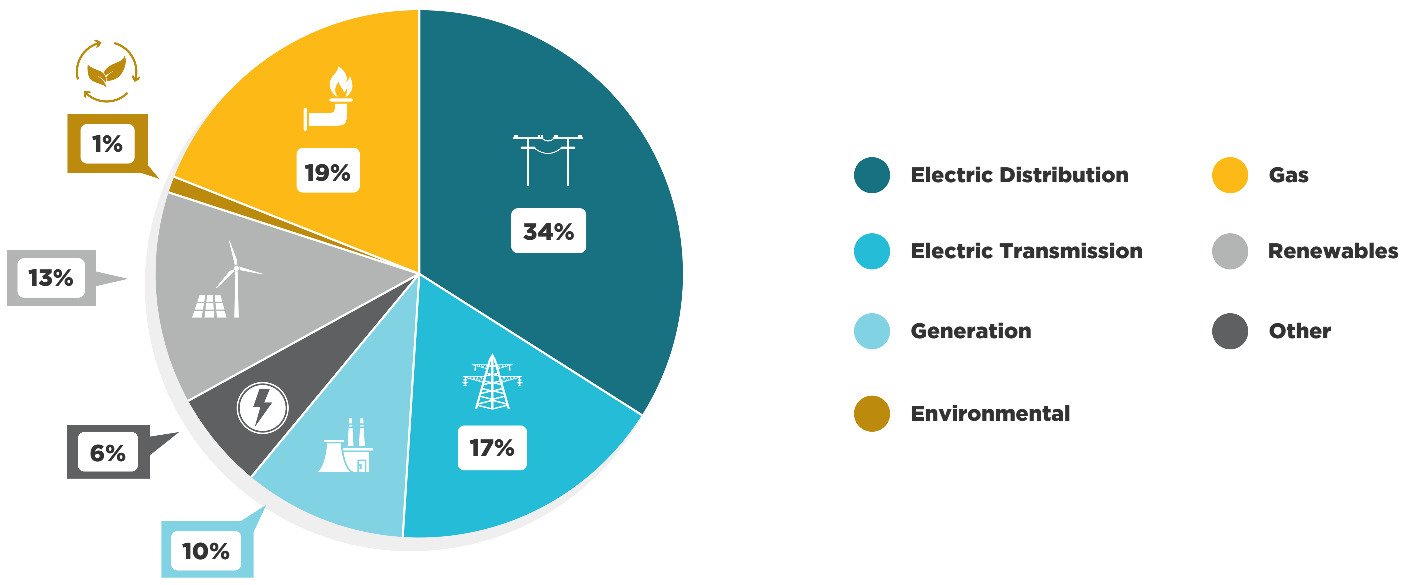
**Utilities are using new, integrated distribution planning approaches that account for uncertainty, transparency (for both carbon reduction and cost control/ equity), locational value, and complexity as they try to tie all these moving parts together.**

Figure 2.1: **Investor-Owned Electric Utility Construction Expenditures for Transmission and Distribution ($ Millions)**




**Sources:** Edison Electric Institute; S&P Global Market Intelligence; ScottMadden analysis

Figure 2.2: **Projected Capital Expenditures of Selected Electric, Gas, and Multi-Utilities by Business Category (2022-2024)**




**Source:** S&P Global Capital IQ Pro/Regulatory Research Associates

## A Bit of History

- DERs and grid modernization are not new, but their evolution is instructive in understanding how and why distribution planning is changing.
- During the first wave of "smart grid" investments, turbocharged as part of the 2009 economic stimulus during the Great Recession, the industry's focus was on automation, control, and "self-healing." Those investments were, for example, in system control and data acquisition (or SCADA) monitoring and control, distribution automation, and advanced metering infrastructure (AMI).
- Soon thereafter, in the mid-2010s, there was discussion about the utility "death spiral" as the photovoltaic solar cost curve began to decline significantly, and there was some fear that customers would self-supply, leaving remaining customers to pay for the grid.
- Policymakers in some jurisdictions that perceived potential grid value in DERs (e.g., New York) and places where conditions were more favorable for rooftop solar (e.g., California, Hawaii) began requiring distribution and/or grid modernization plans.
- The list of jurisdictions requiring distribution system plans has grown (see Figure 2.3 below). In jurisdictions where utilities are formulating and implementing multi-year grid plans, utilities are being directed to go beyond considerations of reliability and resilience. They are being asked to consider policy and other factors and increase transparency and information sharing with stakeholders.

Figure 2.3: **States with Distribution Planning Requirements**

| REQUIREMENTS / STATES | California | Colorado | Delaware | District of Columbia | Florida | Hawaii | Illinois | Indiana | Maine | Maryland | Massachusetts | Michigan | Minnesota | Nevada | New Hampshire | New Jersey | New York | Ohio | Oregon | Pennsylvania | Rhode Island | Texas | Utah | Vermont | Virginia | Washington |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution system plan requirement | ✓ | ✓ | ✓ | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ | | | | ✓ | | | | ✓ | |
| Grid modernization plan requirement | ✓ | | | | | ✓ | | | | | ✓ | | ✓ | | ✓ | | ✓ | | | | | | | | | |
| Hosting capacity analysis/mapping requirement | ✓ | | | ✓ | | ✓ | | | | | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ | | | | | | | | | |
| Non-wires alternatives/locational value requirements | ✓ | ✓ | ✓ | ✓ | | ✓ | | | ✓ | | | ✓ | ✓ | ✓ | ✓ | | ✓ | | | | ✓ | | | | | |
| Storage mandates or targets | ✓ | | | | | | | | | | ✓ | | | ✓ | | ✓ | ✓ | | ✓ | | | | | | ✓ | |
| Benefit-cost methodology/guidance | ✓ | | | | | | | | ✓ | | | | | ✓ | ✓ | | ✓ | | | | ✓ | | | | | |
| Storm hardening requirements | | | | | ✓ | | | | | ✓ | | | | | | | | | | | | | | | ✓ | |
| Required reporting on poor-performing circuits and improvement plans | | ✓ | ✓ | | ✓ | | ✓ | | | ✓ | ✓ | | ✓ | | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ |

**Source:** Grid Modernization Laboratory Consortium

## Integrated Distribution Planning Is Highly Dependent Upon Policy Objectives

- Integrated distribution planning (IDP) goes beyond internal, engineering-led, static planning to open engagement and an objectives-based model.
- Regulatory goals and objectives—often set out in enabling legislation—will drive the scope and types of options to be considered in grid modernization and expansion. These may vary widely. For example:
  - Under the Reforming the Energy Vision proceedings, New York has pursued grid modernization that envisioned, among other things, a roadmap for technology investment to improve grid intelligence and prepare for higher DER penetration levels.
  - Minnesota does not have such a mandate and explicitly includes in its objectives, "Keep customer bills low."
  - Illinois' Multi-Year Integrated Grid Plan objectives include "support[ing] efforts to bring the benefits of grid modernization and clean energy, including, but not limited to, deployment of distributed energy resources to all retail customers, and support efforts to bring at least 40% of those benefits to Equity Investment Eligible Communities."
  - California, seeing that battery storage, customer-sited solar, demand-side management, and electric vehicle infrastructure is growing significantly, recently declared an objective of "optimiz[ing] the integration of millions of DERs within the distribution grid while ensuring affordable rates" by way of a distribution system operator model.
- Policy objectives are evolving, too:
  - More jurisdictions are interested in DER integration to reduce overall grid costs (e.g., non-wires alternatives) and in planning the distribution system to accommodate electrification and DERs in an equitable manner.
  - Climate change concerns may begin to drive resilience as an objective of IDP as well, as regulators are increasingly interested in planning the future T&D system to withstand more frequent and severe storms and rising temperatures.
- Objectives can change over time. In New York, for example, Con Edison noted that its distributed system implementation plans were evolving: "The clean energy policy focus in New York has expanded beyond an emphasis on distribution-connected, small-scale energy resources to one which includes advancing decarbonization through larger-scale resources such as offshore wind and utility-scale solar and fundamental shifts of demand toward electrification of transportation and building heating."

Figure 2.4: **Selected IDP Objectives/Goals/Visions by Jurisdiction: Drivers of IDPs May Vary**

### New York

- Transition to a **Distribution System Platform** and enable efficient investments in DERS
- Roadmap for technology investments to improve the **intelligence of the grid** and prepare for **higher DER penetration** levels
- Provide data to bring greater **transparency** to the planning process
- Address the **tools, processes, and protocols** needed to plan and operate a modern grid

### Minnesota

- Enhance the **customer experience**
- Lead the clean energy **transition**
- Keep **customer bills low**
- **Safe, reliable, affordable** electric service—with an eye to the future

### California

- Modernize the electric distribution system to **accommodate two-way flows** of energy and energy services throughout the IOUs' networks
- Enable **customer choice of new technologies and services** that reduce **emissions** and improve **reliability** in a **cost-effective** manner
- Animate opportunities for DERs to realize benefits by providing **grid services**

### Illinois

- **Create alignment** between the state's energy policy and the utilities' investments and planning
- **Optimize utilization** of electricity grid assets and resources to minimize total system costs
- Support efforts to bring at least **40% of benefits to Equity Investment Eligible Communities***
- Enable greater **customer engagement**, empowerment, and options for energy services
- Reduce congestion, minimize the time and expense of interconnection, and increase grid capacity to host increasing levels of **DERs**
- Ensure opportunities for robust **public participation** through open, transparent planning processes

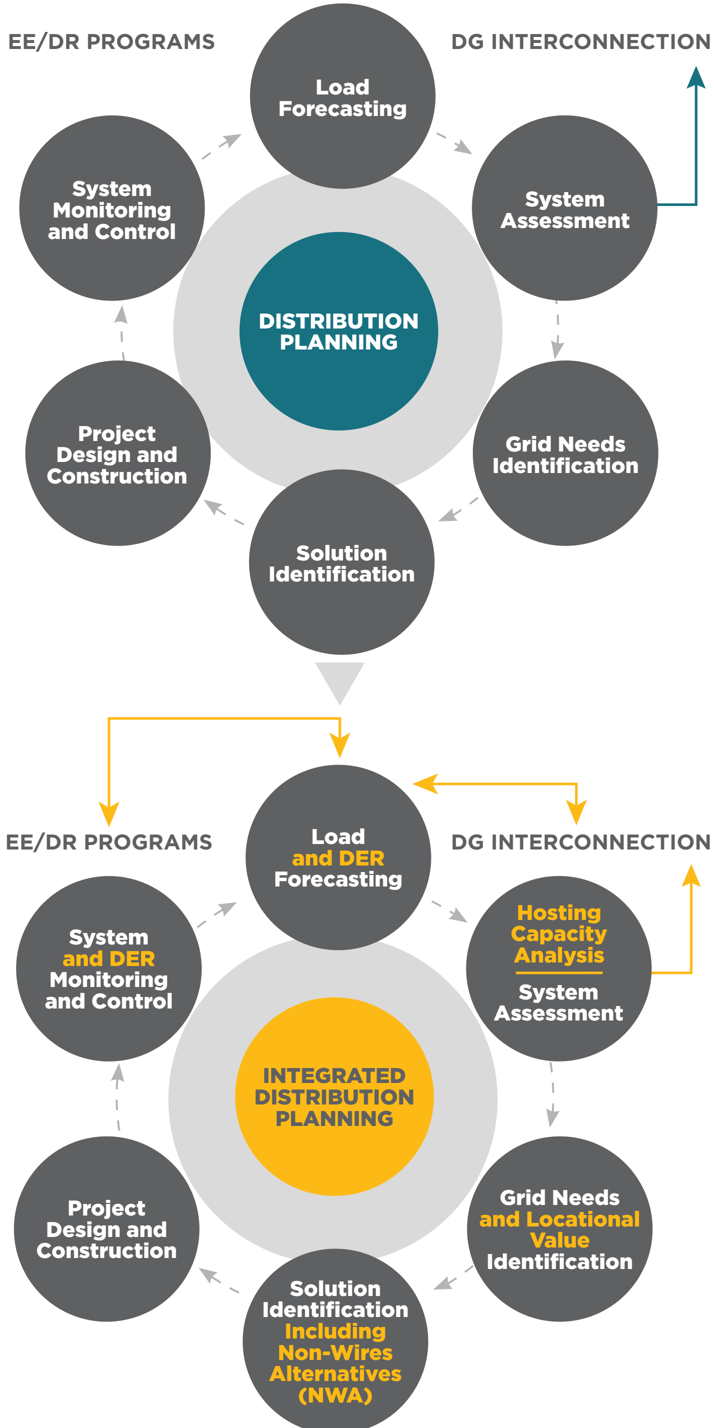
**Note:** *Equity Investment Eligible Communities are geographic areas throughout Illinois which would most benefit from equitable investments by the state designed to combat discrimination and foster sustainable economic growth.

**Sources:** Smart Electric Power Alliance; Climate and Equitable Jobs Act (Ill. Public Act 102-0662); ScottMadden analysis

## What Changes for Planning?

- "Integration" in IDP can involve parts of the value chain adjacent to the distribution grid alone, e.g., transmission and sub-transmission and end-user DERs.
- Traditional distribution planning is driven by expected, deterministic customer and demand growth based on drivers such as population growth, economic growth, and energy usage trends. Historically, it has focused on reliability objectives and planning to system and local peaks.
- The new IDP planning paradigm expands beyond traditional planning drivers, incorporating objectives noted earlier. It considers investments beyond reliability, incorporating evolving and emerging grid features such as:
  - **DER deployment** trends and net load (i.e., demand net of portion served by DERs) and related uncertainty
  - **Electrification,** as some applications—such as fleet electrification—can bring significant point load in a matter of months rather than over years, as might happen with the construction of a new building. With this shorter development cycle, planning for higher voltage infrastructure (transmission and substations) must maintain line of sight to distribution activity, often residing in different utility departments or divisions.
  - **Hosting capacity** – the ability of discrete parts of the distribution grid to accommodate interconnecting DERs without impacting reliability, requiring specialized inverter settings, or without requiring system modifications. This capacity is location dependent, feeder and circuit dependent, and time varying. Regulators and stakeholders demand more transparency under IDP regarding this grid topography and locational value to inform siting and development decisions.

Figure 2.5: **Transitioning to Integrated Distribution Planning**




**Source:** GridLab

## What Changes for Planning? (Cont.)

- **Head-end systems** – hardware and software that receive meter data from AMI and other sensors. Understanding and using end-user data enables both distributed systems operations and controllable, fungible load that can operate as demand-side resources.
- **Investments in new capabilities,** which looks beyond current systems, telecommunication infrastructure, and field assets. IDPs often require utilities to detail their current capabilities and outline the investments needed to achieve customer and grid benefits in the future.

Figure 2.6: **Differences Between Traditional Distribution Planning and Integrated Distribution Planning**

| Traditional Distribution Planning | Integrated Distribution Planning |
|---|---|
| **Core requirements/objectives:** Safe, reliable, affordable grid. | Expanded vision, goals, and objectives: expands beyond safe, reliable, affordable grid; may account for **clean energy goals, grid flexibility, market animation, and customer options and enablement.** |
| **Internal** process within a utility. | Increasing communication, both internally at the utility and externally with **stakeholder engagement** (e.g., help stakeholders understand technical and economic decisions, provide input at defined steps of the process). |
| **Primary distribution grid concerns** focused on thermal overloading and abnormal voltage conditions during a steady state. | **Distribution grid concerns expand** to increasingly include undervoltage, overvoltage, and dynamic power quality impacts. |
| **Deterministic forecasting analysis** based on historical/peak loads and traditional load growth trajectories. | **Increasingly complex and advanced forecasting analysis** incorporating load forecasting with more granular data and DER forecasting. Includes temporal/hourly forecasts to support evaluation of time/energy/limited resources and their locationality. |
| **DERs** included in forecast but **seen as a load modifier;** active targeting of location and DER operation not included in development of planning.<br>**Sourcing solutions** to alleviate grid constraints **limited to traditional utility equipment.** | **Proactive approach to DERs** in planning; planners evaluate traditional and non-traditional solutions (e.g., non-wires alternatives) in response to constraints along the system; guide DER deployment in optimal locations. |
| **Distribution planning is mostly separate** from transmission and generation planning processes. | **Increasingly coordinated and integrated processes** between distribution, transmission, and generation planning (as applicable); work closely with system operations as well. |

**Source:** Smart Electric Power Alliance

## Some Considerations for Grid Investment Decisions

- A goal for distribution planning has long been to identify projects necessary to maintain reliability and safety standards. More recently, policymakers have introduced additional objectives to be achieved through the distribution planning process, such as environmental attributes, capex reduction (or at least making utilities capex/opex indifferent), and energy justice.
- As planning migrates from a standards-based approach to a multi-objective process, determining the prudency of investments is a more complex question. Some projects may require a benefit-cost analysis, while others may use the traditional "just and reasonable" approach.
- Most jurisdictions adopting IDPs envision multi-year plans to accommodate stakeholder processes and to provide stability and consistency as DER adoption, technology development, capital availability, and rate impacts unfold. Some utilities use scenario analysis to reflect a potentially more dynamic planning environment with more input variables.

## Ratemaking Implications

- Ratemaking and rate design approaches are changing—both for multi-year IDPs and for some traditional distribution plans as well—factoring in various potential features of an IDP, such as:
    - Potential stranding of upstream assets with demand-side options
    - "Used and useful" distribution infrastructure built in anticipation of DER evolution
    - Effect on sales volumes where utility rates are kWh volume driven
    - Changing cost (and benefit) drivers and interest in making value of demand reductions and grid locations transparent
    - Balancing affordability and fair and equitable cost allocation
- Performance metrics tied to desired regulatory outcomes are also a growing trend with grid modernization and IDP. These can take the form of enhancements (or reductions) of allowed returns on equity.

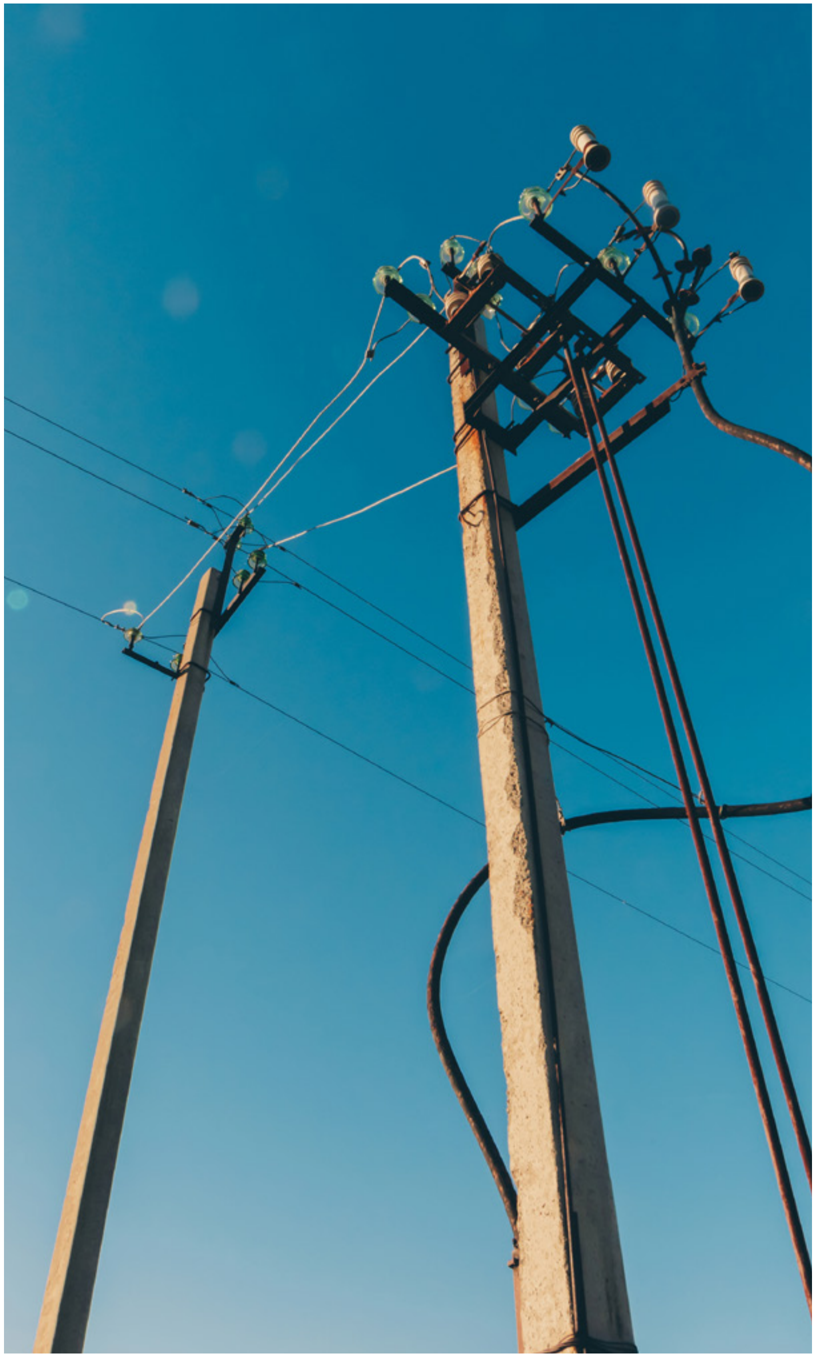


Figure 2.7: **Some Key Features and Issues in IDPs**

| | |
|---|---|
| **Cost-Benefit Analysis** | Across the United States, many utilities and their commissions are looking for a means of comparison between traditional solutions and new options. They are also looking critically at how to demonstrate prudency for the investments needed to enable a more distributed and dynamic grid of the future. Some states, like New York, are integrating environmental values into their cost-benefit frameworks to value solutions that reduce carbon emissions. Establishing an agreed-upon framework is critical to being able to make the appropriate comparisons and decisions for capital infrastructure investments (e.g., substations vs. non-wires alternatives, new technology/program implementation). |
| **Data Access and Hosting Capacity** | Stakeholders have petitioned utility commissions to force utilities to make system and customer data available. This may be to provide them a greater role in utility system planning or enable them to identify favorable locations for project development. Typically, the data of interest includes customer usage data (enabled through data sharing protocols like Green Button Connect), system loading conditions, hosting capacity data, and program- and project-level expenditures. |
| **Value of DERs** | While net metering has been an effective means of promoting the adoption of clean resources, like solar, it has been shown to be a blunt policy mechanism to compensate those resources for the value they provide to the grid. As adoption increases, some states are looking at alternate means of compensating these resources based on the value the resource provides to the grid based on its location or the time of day it is producing energy. |
| **Non-Wires Alternatives (NWAs)** | NWAs are solutions to distribution system constraints that either defer or eliminate the need for traditional infrastructure projects, such as new transmission or distribution lines or substations. Energy efficiency, demand response, and other DERs can either individually or in combination be employed as NWAs. These solutions can be either utility owned or behind the meter. Recently the United States has seen a significant rise in the number of NWA projects proposed and implemented with states, including New York, California, and Arizona, leading the way. In many cases, NWAs represent a new way of doing business for a utility, and the processes to successfully develop and execute an NWA program can span many different organizations. |
| **Electrification** | The conversion of transportation, building heating, and cooking from fossil fuels to electricity has become a common component in many states' carbon-reduction goals and/or legislation. The increase in electric load along with the associated changes in daily and seasonal load shape must be incorporated into the distribution planning process. In addition, some states are also looking to utilities to help facilitate electrification through things such as offerings that provide incentives for switching to electric heat pumps or electric vehicle charging make-ready programs. |
| **Environmental Justice and Equity** | Increasingly, both state and federal policies related to the clean energy transition include components focused on environmental justice and equity. For example, both the federal Inflation Reduction Act and Illinois' Climate and Equitable Jobs Act include provisions that require 40 percent of the overall benefits of climate and clean energy investments to be delivered to disadvantaged communities. This directly influences IDPs as these laws and policies are implemented through them. |

**Source:** ScottMadden analysis

## IMPLICATIONS

**First, utility planning must accommodate a variety of factors beyond reliability and affordability; planning is expanding to include a variety of policy objectives as well.**

**Second, IDPs require a coordinated approach from various utility groups (engineering, energy efficiency, rates, and electric vehicles, among others) as well as stakeholders.**

**Similarly, IDPs must be aligned with other utility plans (e.g., a multi-year energy efficiency plan or rate case). Moreover, utilities are being asked to integrate stakeholder feedback and input, so engaging stakeholders effectively will become critical to IDP outcomes.**

**Finally, distribution planning and investment activity is driving upstream impacts to transmission, presenting challenges to the refresh frequency and lead time necessary for planning these long-lived assets.**

**Sources:**

Grid Modernization Laboratory Consortium Integrated Distribution Planning Overview, Grid Modernization Webinar Series, New Mexico Public Regulation Commission (Mar. 3, 2022); GridLab, Integrated Distribution Planning: A Path Forward (June 2018); Smart Electric Power Alliance, Integrated Distribution Planning: A Framework for the Future (Sept. 2020); Mid-Atlantic Distributed Resources Initiative, Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions (Oct. 2019); Lawrence Berkeley National Laboratory, Electricity Markets & Policy Department, at https://emp.lbl.gov/projects/integrated-distribution-system-planning; ScottMadden analysis.

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# Natural Gas: An Unsettled Outlook

Global dynamics, gas-power interdependence, policy changes, and capital needs complicate the gas industry.

## Supply Hangs On: Meeting the Challenge of Demand

- Domestic demand for natural gas has grown through September 2022, as post-pandemic activity has increased residential and commercial consumption in 2021 and 2022 and cold temperatures drove higher demand in the first half of 2022. Electricity generation demand for gas has increased significantly in 2022, as numerous and lengthy hot spells increased air conditioning demand. Further, as low coal stocks, coal deliverability constraints, and coal plant retirements limited coal-fired generation, generator demand for gas increased in 2022 despite high gas prices.

- Natural gas production continues to grow in response to this demand growth, in part incentivized by high prices, domestic demand, and strong global demand for liquefied natural gas.

  - This continued production growth comes despite more measured capital spending in the upstream sector. U.S. producers have been able to run through their drilled but uncompleted well inventories, reducing incremental capex needs.

  - The International Energy Agency has observed that production growth is "caught between short-term caution on spending and longer-term optimism on export (i.e., LNG) growth potential."

- While U.S. production has kept up with demand, gas in storage remains at recent-year lows going into winter 2022-23. A cool winter and spring transitioned quickly into a warm summer, limiting storage buildup in Q2 2022.


### KEY TAKEAWAYS

**Natural gas supply, demand, and prices are being roiled by competing drivers of demand, policy changes, and potentially increasing effects of the global market.**

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**The war in Ukraine, and related stoppage of pipeline gas imports to Europe, has made Europe a more significant purchaser in LNG markets, and U.S. gas producers and midstream participants are increasing exports insofar as capacity permits.**

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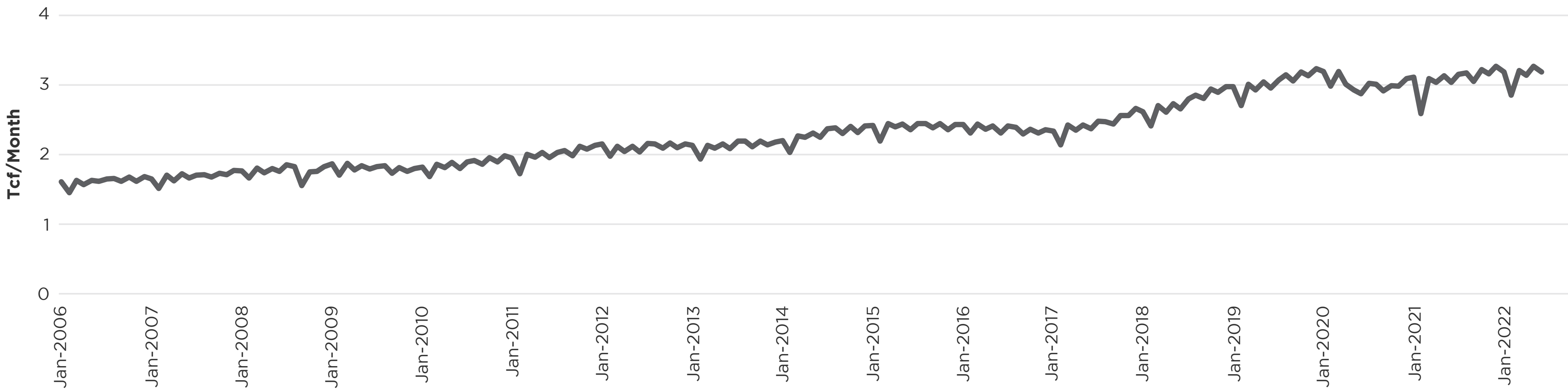
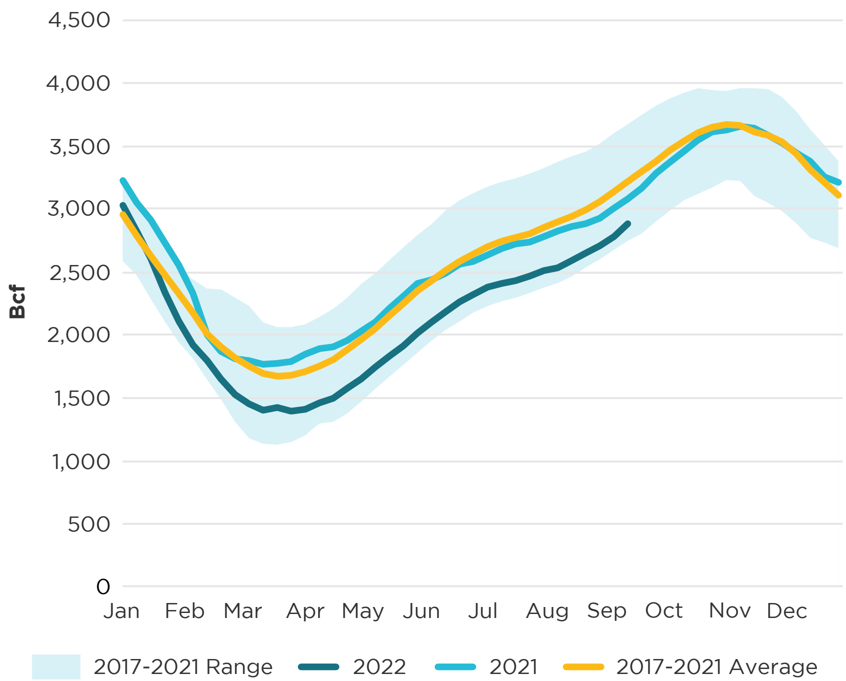
**Gas-power interdependence continues to be an issue for regions across the United States, with gas-fired power as an incumbent and flexible resource to support the clean energy transition. However, supply constraints remain an issue, and system operators and regulators are looking for ways to ensure reliability and energy adequacy in the near and long term.**

Figure 3.1: **Monthly U.S. Natural Gas Marketed Production (Trillion Cubic Feet per Month)**



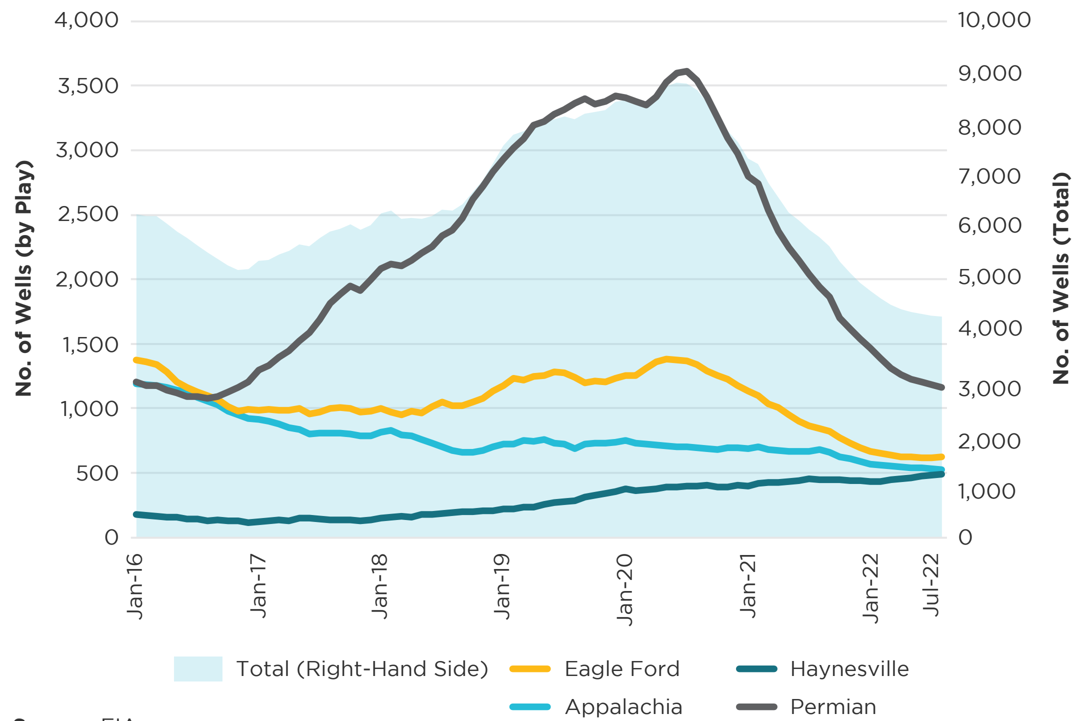

**Source:** EIA

Figure 3.2: **U.S. Lower 48 Weekly Working Gas in Underground Storage (Billion Cubic Feet)**



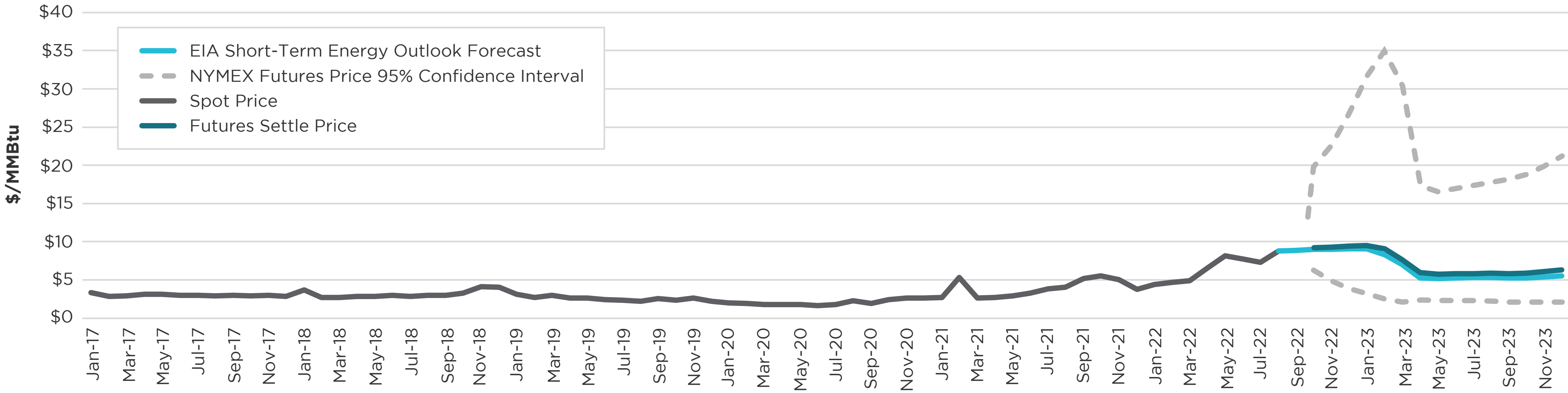

**Source:** EIA

Figure 3.3: **Selected Drilled but Uncompleted Monthly U.S. Gas Well Inventory (No. of Wells)**




**Source:** EIA

Figure 3.4: **Henry Hub Natural Gas Monthly Average Spot and Forward Prices ($/MMBtu)**




**Source:** EIA

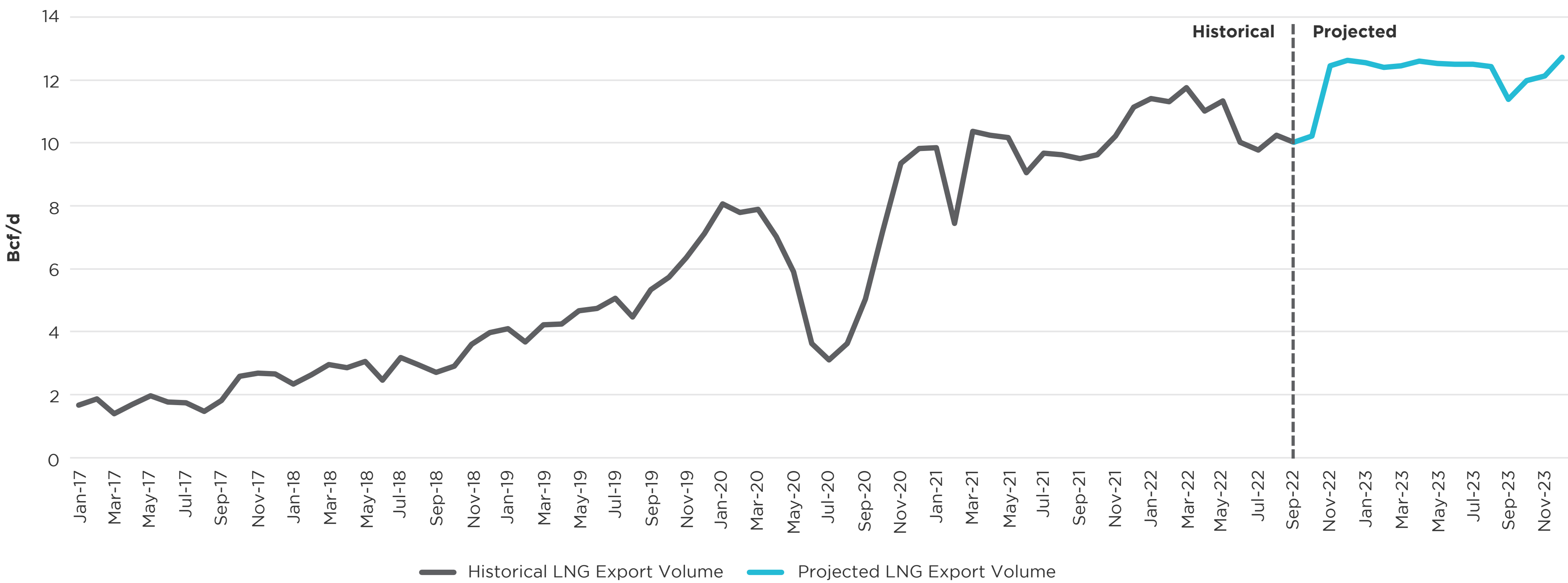
## Natural Gas Prices: Short-Term Spike or Long-Term Trend?

- After years of quiescence, natural gas prices have ticked higher, responding to the supply-demand forces described earlier. Henry Hub prices generally remained below $4/MMBtu until late summer 2021. After a dip in late 2021–early 2022, by March 2022, monthly average prices rose above $5 and have remained elevated.
- A central question for gas market participants is whether and for how long these higher gas prices will last. There are several competing considerations:
  - **Demand response/destruction:** Persistent high prices may reduce gas demand, particularly in applications where there is more price elasticity of demand. In Europe, for example, gas-reliant industries have reduced or stopped production when input prices make the product uneconomic. This has not yet been seen on a widespread basis in the United States.
  - **Global price pressure (or not?):** The United States and Canada are net exporters of gas, meaning that global LNG prices do not necessarily affect domestic prices, although LNG export facilities have been running at capacity. As new export facilities are completed (see LNG discussion later), those exports may be significant enough to compete with domestic demand and impact U.S. pricing.
  - **Renewables vs. coal retirements:** Some analysts note that increasing focus on renewable generation development will reduce total demand for natural gas despite potentially acute needs for balancing in tight power resource conditions. However, offsetting this potential reduced gas demand for power is the continued planned retirements of coal-fired power plants in several regions.
  - **Capex and production:** After years of financial challenges, gas producers have been tightly managing capital for new gas development. It is unclear whether uncertainty about U.S. medium- to long-term hydrocarbon policy (development and end use), long-term European climate policy (for LNG export volumes), and concerns about a slowing economic outlook could reduce or discourage production.
  - **Associated gas:** Prolonged higher (>$100/barrel) oil prices could also continue to motivate oil production, with resulting associated gas volumes.
  - **Weather:** Increased demand due to weather, as was seen earlier in 2022, could provide price signals that would encourage more production which could moderate price increases.

## LNG to Grow as a Demand Driver

- War in Ukraine and related loss of Russian pipeline exports to Europe in 2022 has added to global LNG demand, as Europe has begun to compete with Asian (especially China, Japan, South Korea, and India) LNG demand.
- Even before this year, U.S. LNG exports in 2021 had grown 50% from 2020 volumes, from 44.8 million tons to 67 million tons. The United States was the third largest LNG exporter in 2021, accounting for 18% of global net exports. Part of this growth is driven by the initial commercial operation and high utilization of five large liquefaction trains beginning in 2020, specifically Cameron LNG 2-3, Corpus Christi 3, and Freeport LNG 2-3.
- U.S. LNG exports have risen 12% over 2021 levels, with volumes totaling 74 billion cubic meters, or nearly 54 million tons through the end of August. And while LNG exports to supply global demand are expected to continue given global pricing, new U.S. liquefaction capacity totaling 3.27 Bcf/d is not expected to go online until 2024-25.

Figure 3.5: **Historical and Projected Monthly U.S. LNG Export Volume (Billion Cubic Feet per Day)**

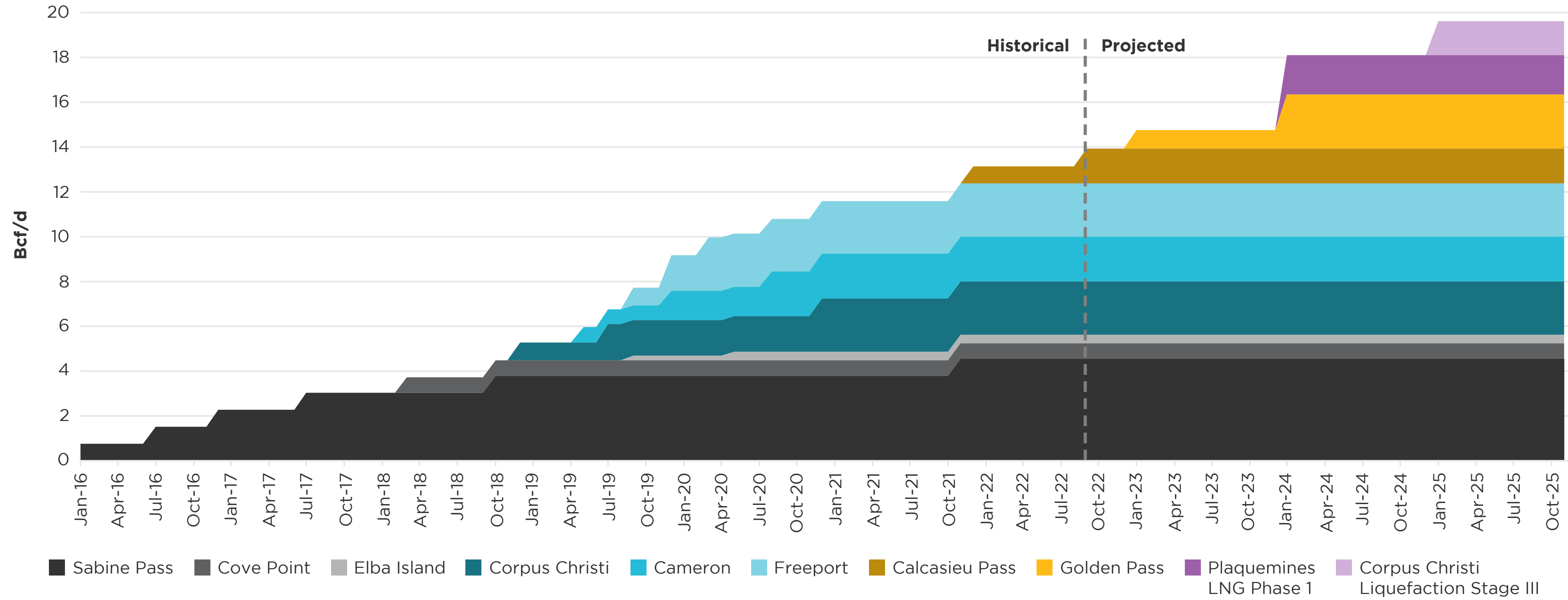



**Source:** EIA

## LNG to Grow as a Demand Driver (Cont.)

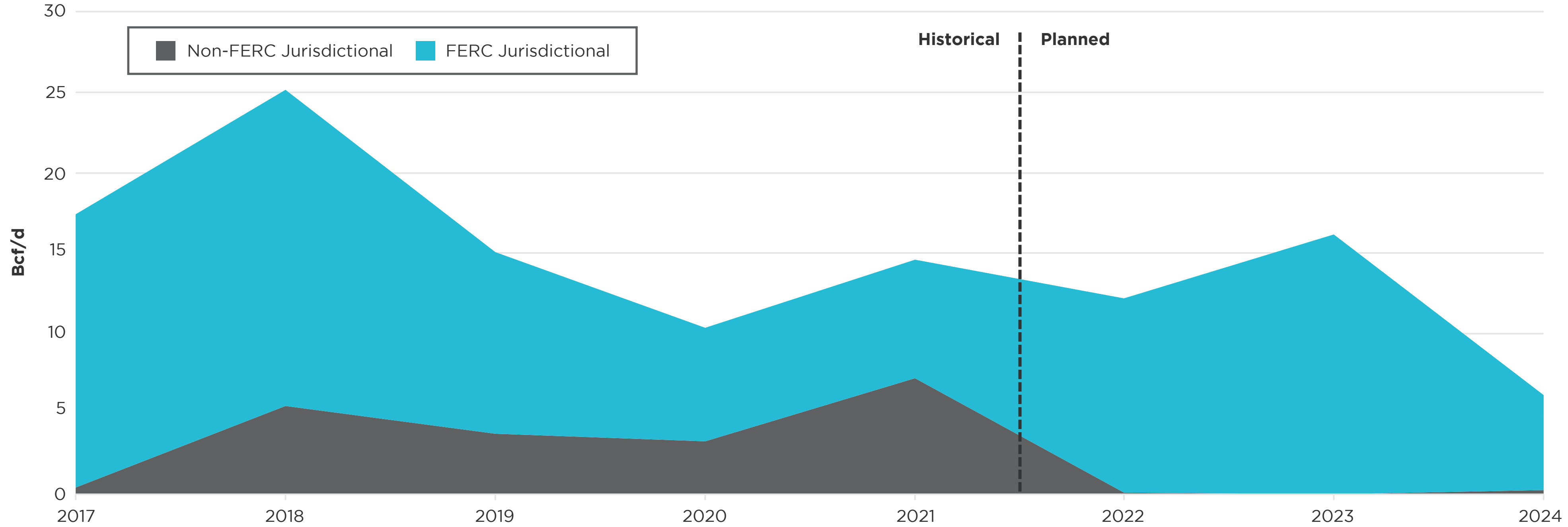
- As noted earlier, real uncertainty exists for long-term demand (2030 and beyond) given European climate change targets. Nonetheless, for now, European buyers are locking in some LNG contracts with American exporters:
  - European-based Engie signed a 15-year sales and purchase agreement (SPA) for 1.75 million metric tons per annum (MTPA) with NextDecade's Rio Grande LNG project in Texas.
  - German utility RWE signed a 15-year heads of agreement (HOA) with Sempra's Port Arthur LNG project in Texas for 2.25 MTPA.
  - Poland's PGNiG signed an HOA with Sempra at its Cameron and Port Arthur facilities.
  - German utility EnBW signed two 20-year SPAs with Venture Global LNG for 1.5 MTPA from the Plaquemines and Calcasieu Pass 2 facilities, starting in 2026.
  - British chemical company INEOS announced plans to begin trading LNG with a 1.4 MTPA deal with Sempra projects.
- Key questions for this development are whether increased global LNG demand is here to stay and at what level might U.S. LNG exports affect domestic gas pricing.

Figure 3.6: **U.S. Historical and Projected LNG Export Nameplate Peak Capacity (Billion Cubic Feet per Day)**




**Source:** EIA

Figure 3.7: **Historical and Planned U.S. Natural Gas Pipeline Additions (Billion Cubic Feet per Day) Approved, Completed, Partially Completed, and Under Construction**




**Notes:** Data as of July 29, 2022

**Source:** EIA; ScottMadden analysis

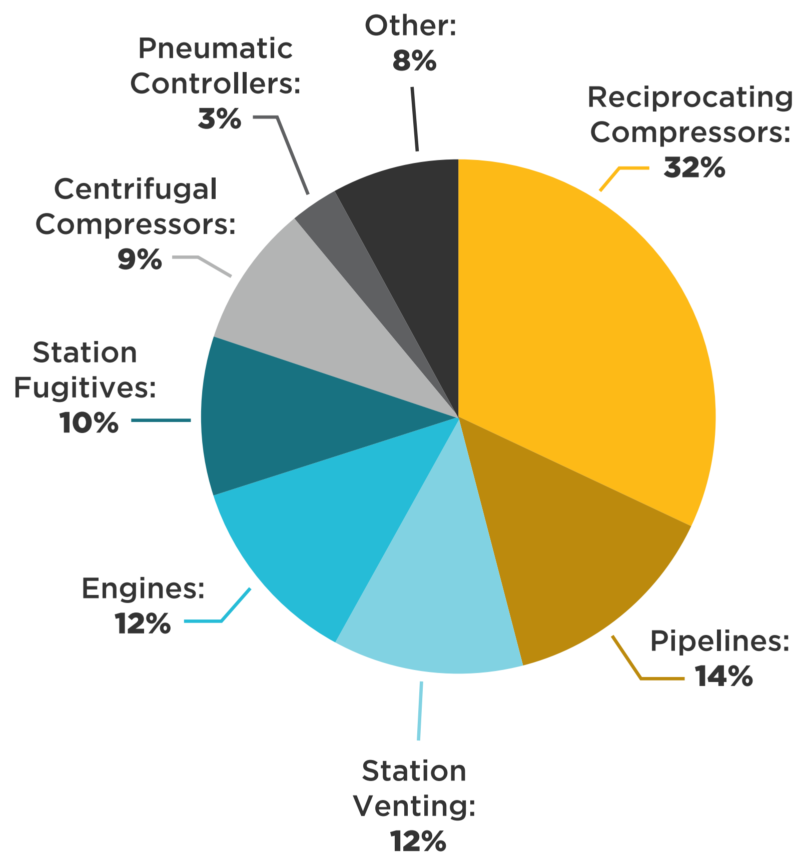
## Pipelines: Moving Ahead or Pipe Dream?

- Because of the dynamics noted above, pipelines have been increasing focus on takeaway capacity that can support LNG growth. For example, the Permian Basin, relatively near Gulf of Mexico export terminals, has 5.5 Bcf/d of incremental gas takeaway capacity projects announced by midstream operators.
- Permitting and certification remains a wild card. Gas pipeline development has been shadowed by FERC's April 2018 announcement that it would revisit its pipeline certification policy with a view to incorporate an assessment of a project's potential greenhouse gas emissions as well as effects on communities. FERC released draft policy statements in March 2022, soliciting comments. While that has not factored into several project approvals to date, new policy statements have not yet been issued.
- Marcellus/Utica takeaway pipeline expansion is needed to further develop those fields, but remains challenging, exemplified by the inability to finish and activate the nearly completed Mountain Valley Pipeline (MVP). Permitting reform, which focused in part on completion of MVP, was proposed by Sen. Manchin (D-WV) as a condition of signing on to the Inflation Reduction Act of 2022 (IRA). However, that provision was removed from the continuing budget resolution passed in late September. It is unclear whether, how, and when it will be reintroduced.

## Mixed Impacts of the Inflation Reduction Act of 2022

- Gas utilities and pipelines have been interested in renewable natural gas (RNG) development as a decarbonization strategy, and some gas utilities are allowed to participate in ownership of RNG infrastructure. The American Gas Association has identified ~2 Bcf/d to 6 Bcf/d of RNG potential. The IRA provides some incentives for decarbonized infrastructure and low-carbon fuels like RNG. However, low-carbon fuel standard credit prices have been declining, offsetting some growth, particularly in the transportation market.
- Kinder Morgan, for example, has created an energy transition ventures group that looks at "attractive opportunities likely to be synergistic with [its] existing infrastructure and expertise." These include opportunities investable today (RNG, renewables), in 1 to 5 years (carbon capture and sequestration), and 5 to 10+ years (hydrogen). Hydrogen is getting an assist from the IRA with a $3/kg subsidy.
- Of course, of particular interest in the IRA are methane fees, which phase in from $900/ton in 2024, rising to $1,200/ton in 2025, and $1,500/ton in 2026. At $900/ton, this yields $277 million. Note that $900/ton and $1,500/ton equate to an implicit $CO_2$ cost of $36/ton and $60/ton, respectively. Those methane fees are applicable to facilities currently required to report emissions to EPA under its Greenhouse Gas Reporting Program (i.e., facilities that emit 25,000 metric tons of $CO_2e$ per year).
  - The EPA's latest estimates are that the entire gas transmission and storage segment emitted about 41 million tons of $CO_2e$ in 2020. Reporting onshore gas transmission pipeline and compression facilities and underground gas storage are estimated to emit 7.7 million tons of $CO_2e$.
  - One group has estimated that the U.S. oil and gas industry will incur a $3.3 billion liability for methane emissions if unremediated.
  - Using a rough $CO_2$ to methane conversion yields about 0.31 million tons of methane for the gas transmission/storage sector. This estimate is slightly higher than is likely to be charged because of emissions thresholds and potential exemptions.

Figure 3.8: **2020 Gas Transmission and Storage Methane Emissions by Source (Total: ~41 $MMTCO_2e$)**




**Source:** EPA


> **"We know that the root of New England's winter electric system reliability challenge is the significant dependence on natural gas in these extreme conditions, along with gas supply constraints."**
>
> **-FERC Commissioner Allison Clements**

## Gas-Power Interdependence: New England's Coal Mine Canary Keeps Chirping

- Gas-power interdependence, long a phenomenon since cheap and lower carbon-emitting natural gas significantly expanded in the early 2010s, continues. And some of the pipeline development difficulties and weather-related disruptions continue to cause concerns for regions heavily dependent on gas-fired power, including those that use gas power to backstop variable energy resources. Certainly, grid issues in Texas and the south-central United States during February 2021's winter storm Uri illustrated the challenges of interdependence across the nation.

- New England has long dealt with this issue, as limited additional gas import capability has been developed despite Marcellus gas a few hundred miles away. The region's energy adequacy/reliability issue is particularly acute during cold spells and extreme winter weather. And resistance to local gas infrastructure development has been an additional constraint for both home heating and power generation. As FERC Commissioner Clements noted, "I'm struck by how long this conversation has been going on."

- In a letter to the Department of Energy, New England's system operator and state governors have called for DOE support in ensuring fuel security. They note that a clean energy transition requires in the near term flexible balancing resources—namely gas-fired—that manage variability of clean energy resources as well as provide home heating.
  - New England is the only region that depends on imported LNG, particularly during winter months. While these imports can be expensive (recently as high as $100/MMBtu in the forward market), they are a key swing resource for the region. The ISO-Governor letter urges continued operation of the Everett LNG facility and exemptions from the Jones Act for LNG deliveries. Currently, there are no U.S.-flagged LNG tankers, and New England must procure from the international market due to Jones Act restrictions.
  - They also propose consideration of an "energy reserve" which would be available through extended periods of severe weather or supply constraints. Market solutions have failed because of the lack of long-term revenue commitments for generators (thus not undertaking long-term fuel commitments) and state-federal jurisdictional gaps and overlaps for issues such as cost recovery.

- FERC conducted a forum in early September to discuss issues and potential solutions. Actionable next steps have not yet been proposed. In the meantime, New England utilities and system operators will have to hope for a normal winter and prepare for potentially high costs for power and gas this winter.

## IMPLICATIONS

**Gas production, pipeline development, and LNG exports continue to provide attractive business opportunities for the gas sector in the near term. With the passage of the Inflation Reduction Act, many "carrots" for decarbonized gas infrastructure—hydrogen, renewable natural gas, carbon capture and sequestration, and related pipeline build—may provide investment opportunities.**

**Gas infrastructure will be needed for the foreseeable future to ensure reliability even through an energy transition. However, uncertainty about future regulatory and policy treatment of that infrastructure could impede further investment. Gas producers, midstream companies, and local distribution companies will have to assess how public policy and demand drivers might affect investments in the medium to long term.**

**For now, with significant focus on reliability (including gas-power interdependence) and meeting critical energy needs, industry participants will likely seek ways to make the most of existing infrastructure.**

**Notes:**

Associated gas is natural gas that is produced along with crude oil and typically separated from the oil at the wellhead.

Cubic meters of gas converted 74 BCM at 1.379 BCM per million tons LNG (see conversions at www.enerdynamics.com/Energy-Currents_Blog/Understanding-Liquefied-Natural-Gas-LNG-Units.aspx).

A heads of agreement is a preliminary, non-binding arrangement that contemplates the negotiation and finalization of a definitive LNG sale and purchase agreement.

$CO_2e$ converted to methane by dividing $CO_2e$ by 25 (see https://www.epa.gov/moves/how-do-i-get-carbon-dioxide-equivalent-co2e-results-nonroad-equipment).

**Sources:**

EIA; IEA; International Gas Union; Columbia|SIPA Center for Global Energy Policy, Opportunities and Risks in Expanding US Gas and LNG Capacity (Sept. 2022); "Sempra Infrastructure and RWE Sign Heads of Agreement for U.S. LNG Supply," Sempra Press Release (May 25, 2022); Barclays, "The Race for Permian Natural Gas Takeaway Relief" (Mar. 17, 2022); "Staff Presentation on Certification of New Interstate Natural Gas Pipelines," FERC News Release (Feb. 18, 2021); "FERC Seeks Comment on Draft Policy Statements on Pipeline Certification, GHG Emissions," FERC News Release (Mar. 24, 2022); Citi Research, "US Master Limited Partnerships and Pipelines & Gas Utilities – Citi's One on One Midstream/Energy Infrastructure Conference – Top Takeaways," (Aug. 23, 2022); Kinder Morgan 2022 Investor Day Presentation (Jan. 26, 2022); Congressional Research Service, Inflation Reduction Act Methane Emissions Charge: In Brief (Aug. 29, 2022); EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020 (Apr. 2022); "US oil and gas industry could face $3.3B in methane fees by 2024," S&P Global Market Intelligence (Sept. 19, 2022); https://twitter.com/ClementsFERC/status/1573039048163315713?s=20&t=XDPvI9mfqMHgrK_dA6GuRA; Letter to U.S. Dept. of Energy Sec'y Granholm from Gordon van Welie, President and CEO, ISO New England, dated Aug. 29, 2022; Commissioner Clements' Statement on Next Steps After the New England Winter Gas-Electric Forum (Sept. 22, 2022).

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# California's Energy Transition: It's Complicated

As California pursues carbon neutrality by 2045, it faces a complicated implementation landscape.

## A Long History of Climate-Focused Energy Regulation

- California has long been an early mover in decarbonizing its energy sector. It has pursued its climate targets through a series of related but separate statutes and initiatives.
- Energy and environmental policies are heavily intertwined and policy is executed through several governmental agencies and institutions, including the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Air Resources Board.
- As policymaking has evolved and implementation has progressed, however, tensions are rising among various objectives for the energy system, specifically: achievability of infrastructure development at its proposed pace; resilience; resource adequacy, diversity, and flexibility; reliability; economic growth; cost and financeability; and affordability.

### KEY TAKEAWAYS

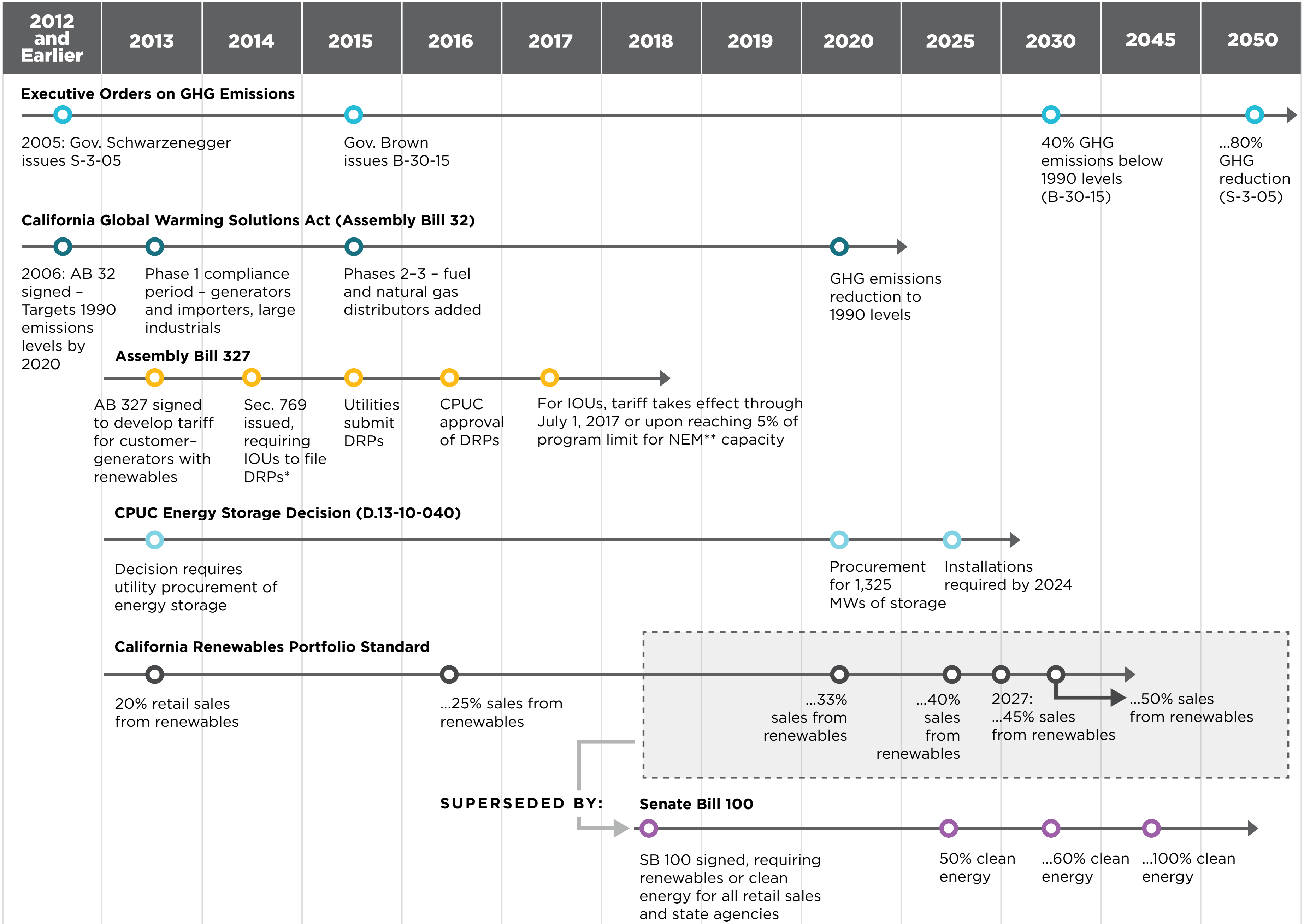
**California's energy transition has driven significant structural changes in power supply and demand dynamics. However, during the transition, systems must focus on resource and energy adequacy and may have to retain dispatchable (some carbon-emitting) resources perhaps longer than planned.**

**Significant investment in the grid, including large, regional transmission, is necessary and anticipated in order to move new large-scale renewable energy across the region as well as modernize the grid.**

**Policymakers will closely monitor cost and affordability through the transition, especially as utilities have more fixed and less volumetric cost drivers.**

**Optionality is key and having many resource "arrows in the quiver" is important until deployment of demand-side options and of more nascent technologies, such as floating offshore wind and long-duration storage, grows.**

Figure 4.1: **Timeline of Selected California Climate-Related Regulation**



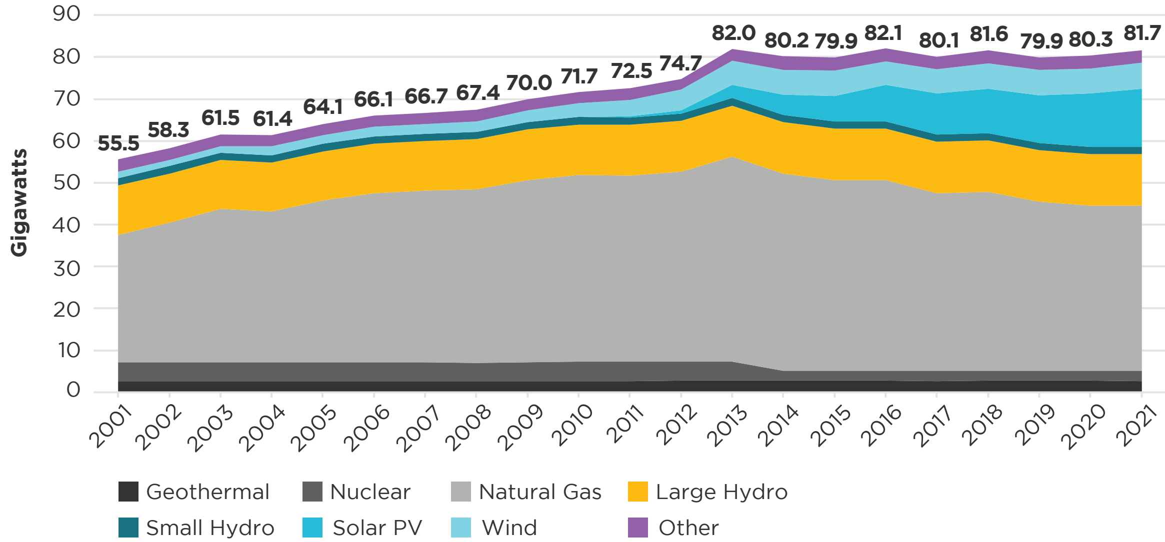

**Notes:** *DRPs are distribution resource plans. **NEM means net energy metering.

**Sources:** ARUP; ScottMadden research

## Shifts in the Resource Mix

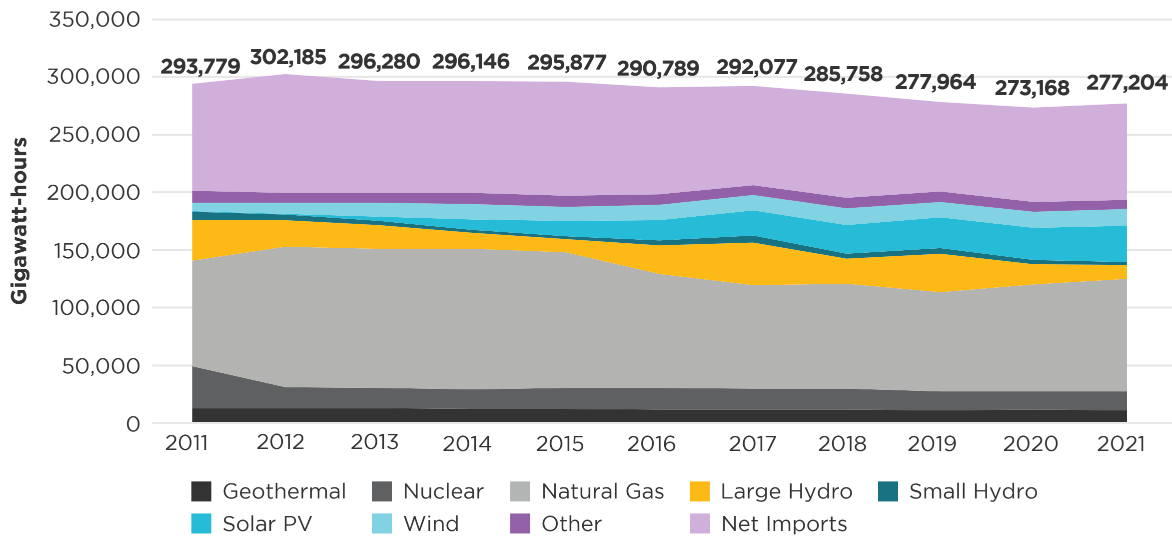
- California has had a dramatic change in its resource mix over the past 20 years, as it has moved toward renewable portfolio standard milestones (33% by 2020; 60% by 2030) and established a goal of 100% renewable and zero-carbon resources by 2045. As a result, the GWh energy mix, including imports, is approximately 50% non-carbon-emitting.
- In pursuing low-carbon resources, the state has seen the retirement of more than 11 GWs of dispatchable and baseload generation since 2013, including more than 9 GWs of natural gas-fired units. However, the baseload 2.3-GW San Onofre Nuclear Generating Station was retired during this time, as well.
- As of year-end 2021, net generation has trended downward for more than a decade. At the same time, California energy imports continue to supply approximately 30% of California's electricity needs, more than any other U.S. state. This has sometimes proved problematic during drought years (with lower available Northwest hydropower) and periods with transmission capacity constraints, including wildfire-related line constraints.
- Moreover, solar PV and wind capacity continue to grow in the state. Periodically lower than expected performance of resources—e.g., wildfire smoke reducing solar output and unfavorable hydro conditions—in recent years has forced California to continue to lean on its gas-fired generation. This reliance on gas generation is particularly acute during late summer, as daylight hours grow shorter (less solar output) while cooling demand remains high.

Figure 4.2: **California Installed Capacity by Fuel Type (2001–2021) (GWs)**




**Sources:** CEC; ScottMadden analysis

Figure 4.3: **California Net Imports and Net Generation by Fuel Type (2011–2021) (GWhs)**




**Sources:** CEC; ScottMadden analysis

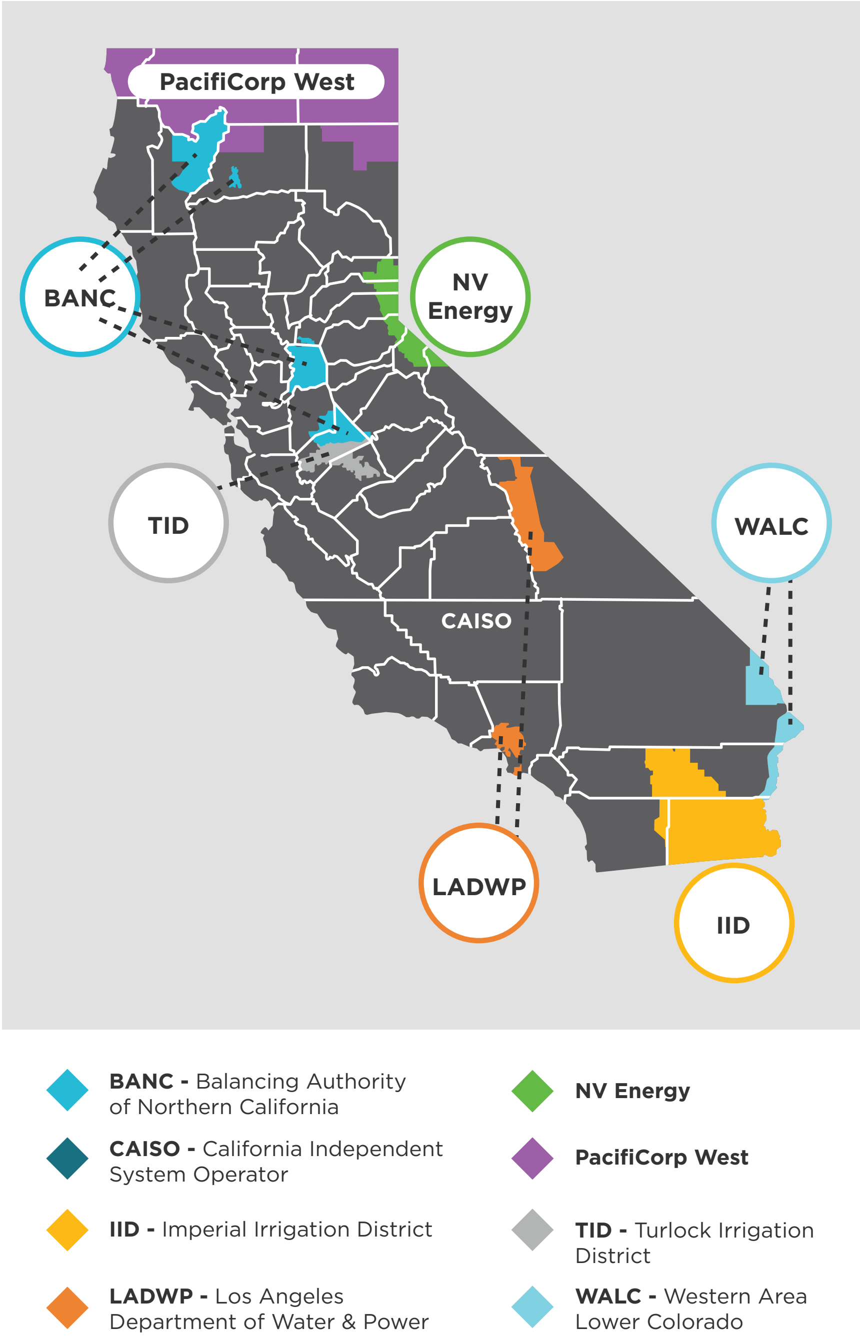
## Unique Features of the California Energy Environment

- California is blessed with several energy resources, which in theory should support transition to a 100% non-emitting power portfolio.
    - It has abundant sunshine, which has supported the deployment of 10 GWdc of rooftop solar and nearly 20 GWdc of utility-scale solar, including community solar.
    - Because of local seismic conditions and associated underground heat creation, California has long been a leader in geothermal resources. Those resources totaled about 2.7 GWs and comprised 6% of in-state GWh generation in 2020 and 2021. However, most facilities were put in place before 2000; only 326 MWs of geothermal resources have been added since then.
    - California has the nation's second-largest conventional hydroelectric-generating capacity after the state of Washington. However, hydropower's contribution is highly variable and dependent on hydrological conditions, specifically rainfall and snowpack. California is prone to drought—2021 was the driest year in nearly a century—and in-state hydroelectric power supplied only about 6% of California's utility-scale net generation, down from nearly 18% in 2017.

  Note that two of the three resources above—solar and hydropower—are dependent upon environmental conditions.

- Other societal and policy preferences also play into California's energy environment:
    - Historically strong opposition to maintaining or expanding in-state nuclear power
    - Pursuit of community choice aggregation (CCA), which has allowed some communities to purchase renewable energy, has complicated the assurance of resource adequacy of CCA load-serving entities
    - Frequency of wildfires caused by seasonal winds, vegetation management, drought, and ignition sources (human actors and utility infrastructure)
- As a result, California's unique environment both promotes and complicates the state's energy transition.

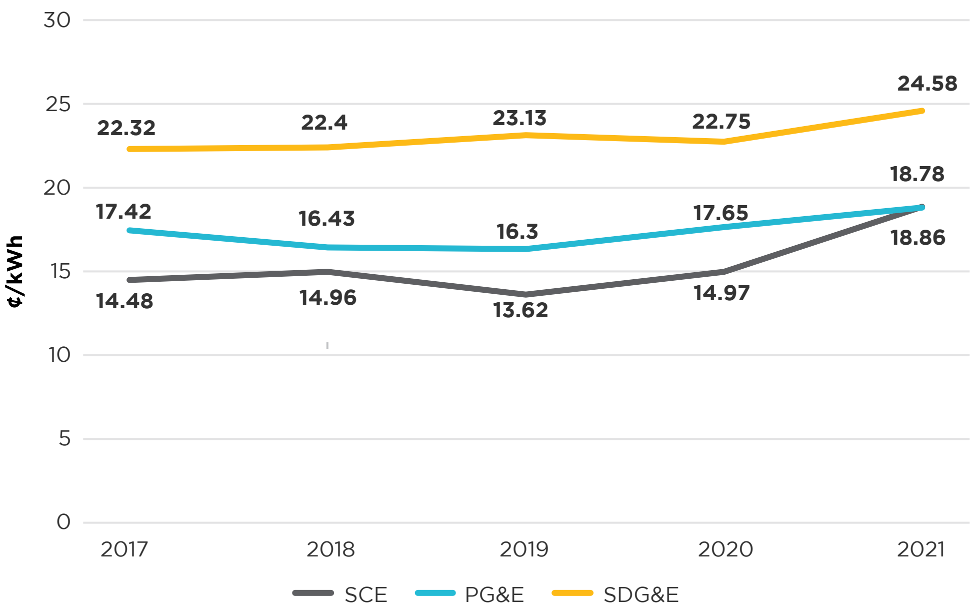
Figure 4.4: **California Balancing Authority Areas**



## Cost and Affordability Are Areas of Focus for Regulators

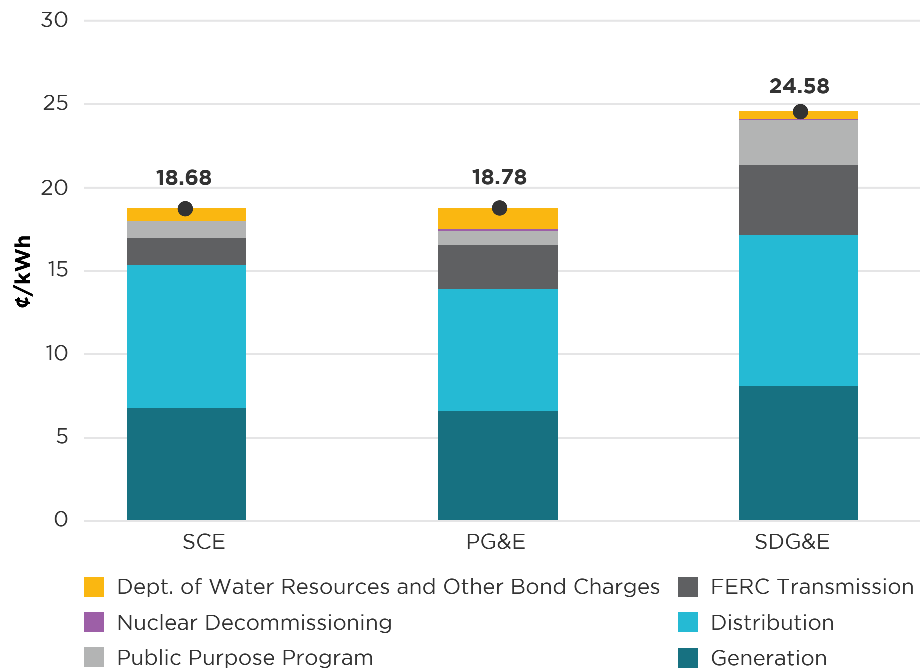
- The reconfiguration and expansion of utility facilities pursuant to a transition of energy infrastructure to high levels of non-emitting resources and distributed resources require significant levels of investment. Much of this will likely be recovered from customers through rates.
- The CPUC is required to report annually on costs of utility programs and activities. It is also charged with recommending actions over the next 12 months to limit utility cost and rate increases consistent with the state's energy and environmental goals, including goals for reducing emissions of greenhouse gases.
- Some observations from the latest CPUC reviews:
  - **High rates, "average" bills:** With flat to declining load growth as a result of distributed resources (encouraged by net energy metering (NEM)) and efficiency as well as effects of some customers leaving utility-bundled service for CCA, average residential rates for California's investor-owned utilities (IOUs) are among the highest in the nation and have increased between 5% and 10% per year since 2013. However, Californians' residential bills are not the highest in the nation. In 2020, residential average bills were 25th, 85th, and 87th for the three major IOUs in the state, respectively, compared with 200 U.S. IOUs (with a ranking of 1st having the highest bills).

Figure 4.5: **Total System Average Electric Rates (2017–2021) (¢/kWh)**




**Source:** CPUC

Figure 4.6: **2021 System Average Electric Rate Component Values (¢/kWh)**




**Source:** CPUC

## Cost and Affordability Are Areas of Focus for Regulators (Cont.)

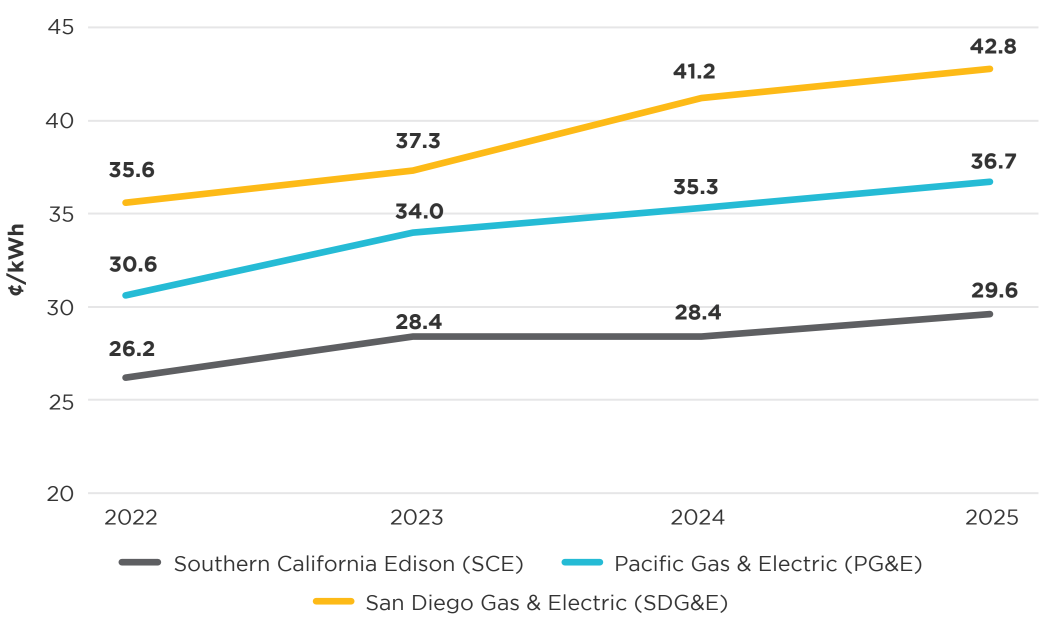
- **Increasing rates:** Transmission and distribution infrastructure investments and operations costs are key drivers of increasing rates, and CPUC expects continued upward pressure on rates due to “climate change-driven” wildfire mitigation costs and electrification needs. In fact, as final payments on bonds that arose from the cost of electricity restructuring and the 2000-01 energy crisis are being made, new costs of the state’s wildfire fund are taking their place. The bottom line: adaptation costs—such as PG&E’s proposed 10,000-mile, $11 billion distribution undergrounding effort—will be incurred along with transition costs over the near to medium term.

- **Rethinking volumetric rates:** CPUC has expressed concern that increasing fixed costs, current rate design, and California’s current NEM framework and other distributed energy resource (DER) incentives may result in cost-shifting to low- and middle-income non-participants. CPUC is looking at revising NEM payments and has suggested potentially changing the current framework of cost allocation and rate design.

- One commentator recently suggested “insulating” electric rates from nearly $39 billion in wildfire-related costs to ensure “policy effectiveness, equity, and overall affordability,” which it characterizes as key for decarbonization acceptance. This commentator suggests recovering those costs through the state’s general fund or other mechanisms.

- Wildfire costs and extreme weather system impacts, as well as unusual demand-side effects of COVID restrictions, have been so significant that it has been difficult to discern the cost and affordability impacts of transition absent those factors. Industry and policymakers will pay close attention to power prices and system costs as California’s transition continues.

Figure 4.7: **Forecasted Bundled Residential Average Rates (Nominal ¢/kWh)**




**Source:** CPUC

> **“Average electricity bills for PG&E bundled residential customers are forecast to rise at an annual average rate of about 9 percent, about 4 percent for SCE customers, and about 8 percent for SDG&E between now and 2025, implying that these households’ energy bill will become less affordable if household incomes track the assumed inflation rate of 2.4 percent.”**
>
> **–California PUC (May 2022)**

## Transmission Investment Is Required

- As mentioned earlier, California currently imports about 30% of its power. Significant imports and exports as well as intrastate transfers are expected as demand for non-carbon-emitting resources (including storage and behind-the-meter solar PV) continues to grow, vehicle electrification expands, and natural gas-fired generation declines by a projected 15 GWs by 2040.
- California's Senate Bill 100 (SB 100), which requires energy from renewable and zero-carbon resources supply 60% of retail sales by 2030 and 100% of retail sales by 2045, has focused policymakers and system planners on long-term grid requirements. California planners have issued their first 20-year transmission outlook, seeking to establish a planning baseline and initiate development activities given that lead times for transmission of "eight to ten years are reasonable or even optimistic."
- A joint agency report that analyzed SB 100 projected a 2040 statewide peak load of 82 GWs, compared with a current 2031 forecasted peak of 64 GWs (an increase of more than 28%). To meet that demand, California projects the need for more than 120 GWs of additional zero-emissions capacity, with more than 24 GWs of wind resources split between in-state and out-of-state resources. Interestingly, it anticipates about 10 GWs of offshore wind. However, because California's continental shelf falls away quickly, such development would likely require more novel, expensive, and technically challenging floating wind technology.
- California ISO's (CAISO) planning outlook estimates that an incremental $30.5 billion in transmission development will be required to integrate these resources under its base case scenario. The estimated cost for upgrades to the existing CAISO footprint is $10.74 billion, while offshore wind integration is more than $8 billion and out-of-state wind integration is $11.65 billion. These incremental costs total approximately $15/MWh (1.5¢/kWh) phased in between 2030 and 2040.

Figure 4.8: **CAISO 20-Year Transmission Plan Illustrative Diagram of Transmission Development**


| Transmission Development | Estimated Cost ($ billions) |
|---|---|
| **Upgrades to existing ISO bulk transmission footprint consisting of:**<br>• 30 kV and 500 kV AC lines<br>• HVDC lines<br>• Substation upgrades | **$10.74 B** |
| **Offshore wind integration consisting of:**<br>• 500 kV AC lines<br>• HVDC lines | **$8.11 B** |
| **Out-of-state wind integration consisting of:**<br>• 500 kV AC lines<br>• HVDC lines | **$11.65 B** |
| **Total estimated cost of transmission development** | **$30.5 B** |

**Source:** CAISO

## Growing Pains: Resource Adequacy, Energy Adequacy, and System Operations

- With the rapid incorporation of variable energy resources, particularly solar PV, into the resource mix, California's grid operator has long observed issues of supply/demand imbalance in the form of the famous "duck curve," going back to at least 2013.
- Traditional planning reserve margins (PRMs) have addressed resource availability at peak hours. But planners assume that adequate PRMs ensure adequacy at all hours of the year. California has experienced seasonal (especially late summer) peaks that have pushed further into evening hours just as solar output falls dramatically, causing system stress. This is exacerbated by rising net load (i.e., load net of solar PV, wind, and other distributed resources), which also ticks up during those late afternoon/early evening hours.
- California has also experienced "too much of a good thing": overproduction by wind and solar resources, particularly in the spring months. CAISO has been forced to curtail output where there is systemwide or local oversupply. This has implications for solar developers, which are uncompensated during those hours.
- The Western Energy Imbalance Market, now beginning its eighth year, has been effective in transferring available energy across the market footprint. However, as noted by CAISO, it is not a substitute for in-area resource sufficiency—both for capacity and flexible ramping—and is not intended to allow balancing areas to "lean on" other member areas.
- The state's resource and energy adequacy issues stem from the reliance on imports (discussed earlier), and the retirement of flexible dispatchable resources at a greater pace than clean dispatchable resources (battery storage, demand response) are coming into service. Grid-scale battery storage deployment in California, now at about 3.6 GWs, has been helpful in providing some flexible resources, but batteries may be inadequate for longer-duration events like heat waves.

## Growing Pains (Cont.): Pursuing Flexibility

- Regulators, policymakers, and system operators are thus pursuing various (and some unexpected) strategies as described in Figure 4.9 below. All of these approaches illustrate that successful transition while preserving reliability requires a preservation of real options on flexible assets until there is more certainty of resource development and performance.
- Going forward, a remaining issue for California's resource and energy adequacy will be the impact of resource mix changes (specifically decarbonization policies) and the correlation of weather phenomena (extreme weather, hydro availability, cooling water availability, etc.) across the West that might affect resource sharing and import capability into California.

Figure 4.9: **Strategies That Policymakers and System Operators Can Pursue**

| | |
|---|---|
| **Extending gas generation** | CAISO has designated several gas-fired units as reliability must-run, extending their operating lives through at least 2023. California has also extended deadlines for compliance with once-through cooling requirements for certain units near load areas, allowing those units to avoid scheduled retirement. |
| **Extending nuclear and supporting resources via a state "reliability reserve"** | In a surprising move, the confluence of potential federal funding and the expected retirement of large-scale, non-emitting generation led the state to approve the extension of the highly contested Diablo Canyon nuclear station. This extension is pursuant to a $5.2 billion, 5 GW "strategic electricity reliability reserve" that will allow the state's Dept. of Water Resources to "[add] resources to the electrical grid to ensure electrical grid reliability and support the clean energy transition." While zero-emissions resources are preferred (demand response and efficiency first, then renewables), "feasible, cost-effective conventional resources" can also be funded. |
| **Establishing a ramping product** | While CAISO has a flexible ramping product, it now proposes developing a new, flexible real-time ramping product to be procured by location and potentially expanding the current product's time horizon beyond the current 15-minute period, perhaps to several hours. |
| **Updating resource adequacy planning** | CPUC has proposed development of new resource adequacy requirements that consider energy and capacity needs across all hours of the day, ensure sufficient flexible capacity, and strengthen requirements for imports to meet resource adequacy requirements. |
| **Incentivizing demand-side options** | CAISO has enhanced compensation for demand response and extended it to residential customers. And demand response, including ISO real-time outreach via text messages, has been an important element of preserving reliability. However, behavioral changes remain difficult in extreme heat environments (e.g., turning down air conditioning). |

## IMPLICATIONS

**Energy transition can be complex, especially as policymakers pull different levers on demand, supply, fuel choice, and regional power purchases. Weather (including extreme weather) and asset mix and characteristics will continue to be factors in energy system planning and operations regardless of transition aspirations and timelines.**

**As other states move toward energy transition, they, too, face challenges. California has demonstrated that deployment of batteries and other non-emitting resources needs to be strategic, and the market design, including wholesale product deployment, needs to support that.**

**Resource adequacy standards need to be clearly defined, and regulators and policymakers need a measured approach to avoid retiring reliable, dispatchable resources too quickly. ISOs and balancing authorities need to move on multiple fronts: resources, transmission, reliability standards, market design, battery deployment, ancillary services, interstate transfers, and more.**

**Notes:**

CCAs are governmental entities formed by cities and counties to procure electricity for their residents, businesses, and municipal facilities. CCA programs have several unique characteristics. When a CCA launches, IOU electricity customers in the designated service area are automatically opted-in to CCA service, and they have to opt-out to continue to be served by the IOU. Once established, a CCA purchases power for its customers. The procurement rates are not regulated by CPUC but instead are regulated by the CCA following its own public process.

While the CCA is responsible for procurement, the IOU still provides other services, such as transmission, distribution, metering, billing, collection, and customer service. The nature of these divided but related responsibilities requires some form of partnership between the CCA and the IOU on many operational issues. For instance, the bill that CCA customers receive comes from the IOU and identifies the amount that a customer owes to the CCA for procurement and to the IOU for the remaining electric services. (Source: CPUC)

**Sources:**

California Energy Comm'n (CEC); California ISO (CAISO); Senate Bill 100, "The 100 Percent Clean Energy Act of 2018"; "Growing Oregon Wildfire Threatens California Transmission Lines, State Issues Grid Warning," KQED.org (July 10, 2021); EIA, Today in Energy, "Smoke from California wildfires decreases solar generation in CAISO" (Sept. 30, 2020); California Dept. of Conservation; EIA, California State Energy Profile – Analysis (updated Mar. 17, 2022); California Dept. of Fish and Wildlife; California Public Utilities Code §§913, 913.1; CPUC, 2022 Senate Bill 695 Report (May 2022); CPUC, 2021 California Electric and Gas Utility Costs Report (Apr. 2022); "PG&E Leaders Detail Undergrounding Timeline, Cost Targets," T&D World (Feb. 11,2022); Energy Innovation, California Energy Policy Simulator 3.3.1 Update (June 16, 2022); CAISO, 20-Year Transmission Outlook (May 2022); CEC, CPUC, and California Air Resources Board, 2021 SB 100 Joint Agency Report (Mar. 2021); CEC, SB 100 Starting Point for the CAISO 20-Year Transmission Outlook (Sept. 13, 2021); Electrek, "California governor calls for a massive 20 GW of offshore wind by 2045" (July 26, 2022); Clyde & Co., "Opportunities and Challenges in Floating Offshore Wind" (Jan. 21, 2022); ScottMadden, "Revisiting the Duck Curve: An Exploration of Its Existence, Impact, and Migration Potential" (Oct. 2016); National Regulatory Research Institute (NRRI), The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study (Mar. 2021); "Curtailment Tracker: CAISO Systemwide Curtailments Climb in June on Capacity," Megawatt Daily (July 18, 2022); EIA, Battery Storage in the United States: An Update on Market Trends (Aug. 2021); CAISO News Release, "ISO Board Takes Action to Boost Summer Grid Reliability" (Sept. 1, 2022); NRRI, The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study (Mar. 2021); California Assembly Bill No. 205, enacted June 30, 2022; "California Legislature Passes Bill to Support Reliability Reserve, Lifeline for Diablo Canyon Nuclear Plant," *Power* (June 30,2022); AB 205, at §25791(c); ScottMadden analysis.

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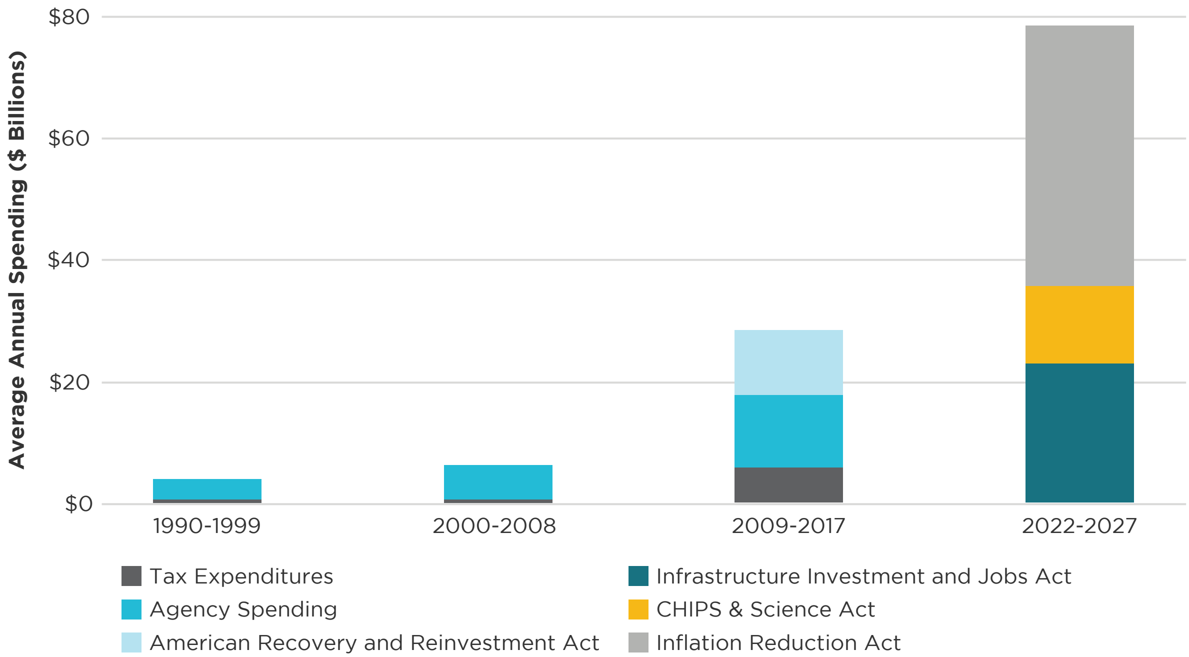
# Inflation Reduction Act of 2022: Decarbonization or Bust

A summer surprise from Congress ushers in a new era of sweeping federal energy and climate policies.

## Unprecedented Amounts of Federal Funding Could Dramatically Reshape the U.S. Energy Landscape

- In late July, Senators Schumer (D-NY) and Manchin (D-WV) emerged from clandestine meetings to announce an unexpected agreement to pass sweeping energy and climate legislation.
- By using the budget reconciliation process, the legislation quickly passed through the U.S. Senate and U.S. House of Representatives along party-line votes.
- Less than three weeks later, President Biden signed the Inflation Reduction Act of 2022 (IRA), which represents an investment of $369 billion in energy and climate spending over the next 10 years.
- The IRA is expansive even in comparison with past major funding legislation such as the American Recovery and Reinvestment Act of 2009 (the Great Recession stimulus package) or the Infrastructure Investment and Jobs Act passed in late 2021 (see Figure 5.1).

Figure 5.1: **Selected Federal Climate-Related Spending (1990-2027 Projected) (Inflation Adjusted)**




**Source:** Rocky Mountain Institute

## KEY TAKEAWAYS

**The IRA is an unprecedented $369 billion in federal energy and climate funding that will dramatically transform the energy industry.**

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**By using multiple levers available to the federal government, the legislation is designed to lower costs of carbon-free technologies, accelerate the rapid decarbonization and energy transition, and shape domestic industrial policy.**

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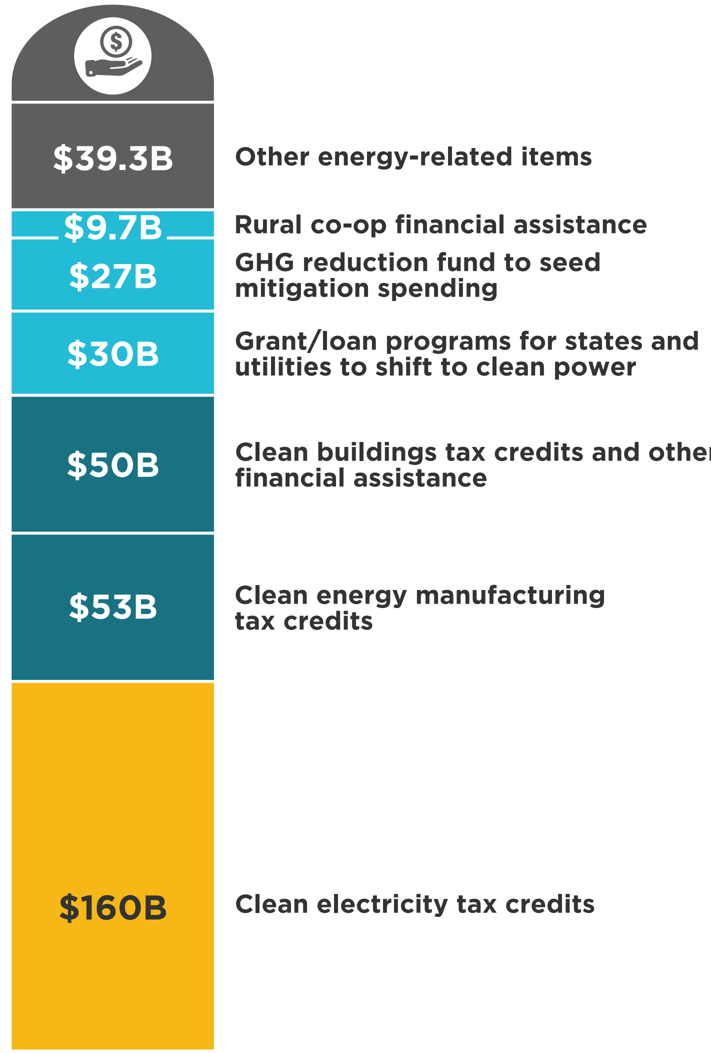
**Success in this new policy environment will require energy companies to identify and prioritize IRA funding, prepare and organize for increased complexity, and closely monitor ongoing developments.**

## Applying Multiple Levers Available to the Federal Government

- The IRA will impact the energy industry through four primary levers:
  - **Tax Credits:** Extends and modifies existing tax credits—i.e., the renewable production tax credit (PTC) and the investment tax credit (ITC)—and creates new tax credits (i.e., clean electricity PTC/ITC)
  - **Appropriations:** Provides funding to a variety of programs across more than a dozen federal agencies
  - **Loan Guarantees:** Expands current and authorizes new lending authority through the DOE Loan Program Office (LPO)
  - **Fossil Fees:** Increases royalty payments on fossil leases on government land and creates a new methane emissions fee, which focuses on "excess" methane emissions
- At a high level, most of the tax credits and appropriations fall into categories and appropriation amounts shown in Figure 5.2 at right. In addition, the IRA includes $2 billion in transmission financing.
- One notable detail in the IRA is that clean electricity tax credits will not begin to expire until the later of (a) 2032 or (b) when greenhouse gas (GHG) emissions from electric generation decline 75% compared to a 2022 baseline.
- Meanwhile, the most overlooked program may be the new Energy Infrastructure Reinvestment Program, administered through the Department of Energy's LPO.
  - The IRA authorizes $250 billion in lending authority for this new program.
  - Through the program, the LPO may offer direct loans or loan guarantees for projects that:
    - Retool, repower, repurpose, or replace energy infrastructure that has ceased operation
    - Enable operating energy infrastructure to avoid, reduce, utilize, or sequester GHG emissions
  - Lending authority for existing LPO loan guarantee programs was also increased through the IRA.

Figure 5.2: **Overview of IRA Tax Credits and Investments**

### The IRA boasts $369 billion in energy and climate change spending over 10 years



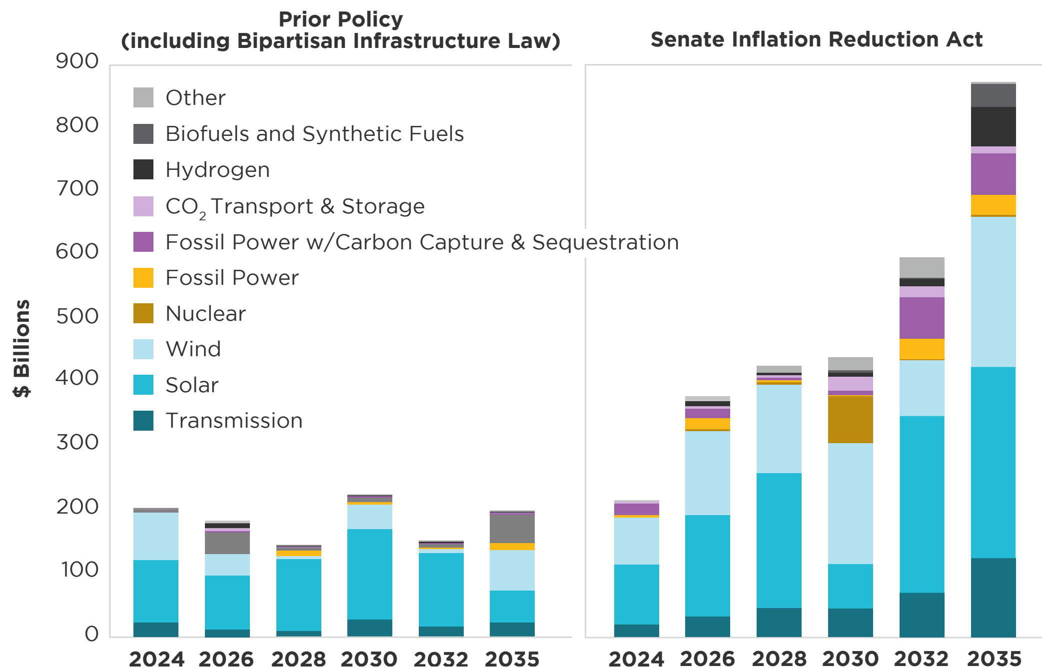

**Note:** As of Sept. 13, 2022.

**Source:** S&P Global

## Some Key Themes Illuminate the “Where” and “How” of Legislative Impacts

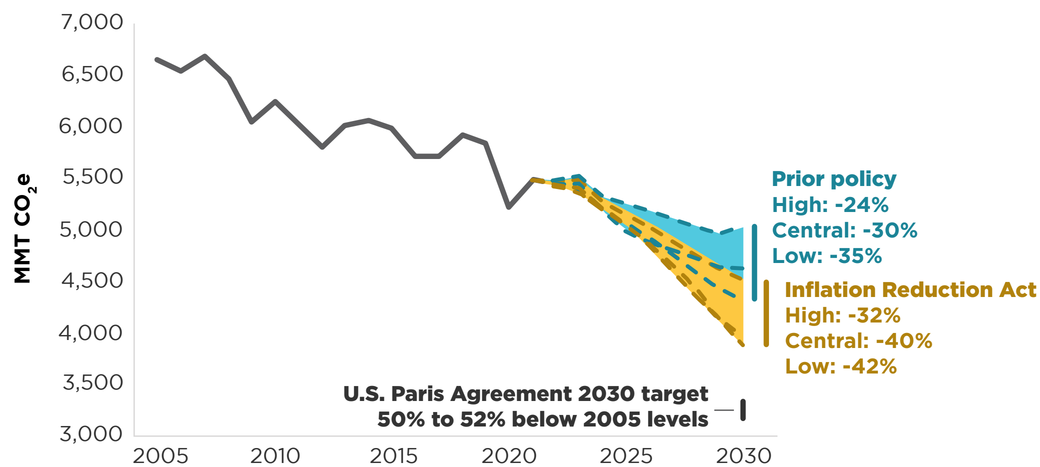
- The IRA is designed to place a clear emphasis on the following themes:
  - **Lower Costs:** Previous attempts to address climate change relied on “sticks” such as cap-and-trade mechanisms or the controversial Clean Power Plan. The IRA, however, focuses overwhelmingly on “carrots” by offering incentives and investments designed to significantly lower the cost to manufacture and deploy carbon-free technologies, deploy energy efficiency measures, and electrify buildings. The handful of “sticks” include the increase in royalty payments on fossil leases and the introduction of the methane emission fee.
  - **Reduce GHG Emissions:** The law accelerates rapid decarbonization and the energy transition by deploying unprecedented policy support in terms of dollars and duration (i.e., 10-year time horizon). Further, the law provides incentives and investments across the entire energy supply chain—raw materials, manufacturing, deployment, and consumer adoption—for both existing technologies (e.g., new wind, solar, and storage and existing nuclear) and more nascent technologies (e.g., small modular reactors, hydrogen, and carbon capture).
  - **Drive Industrial Policy:** To ensure long-term energy security and economic growth, the IRA links numerous provisions, incentives, and bonus credits to domestic content requirements and prevailing wage and apprenticeship requirements. The law places an emphasis on building domestic supply chains for solar, wind, battery storage, and electric vehicles.
- Some early analysis of the IRA suggests that lower costs will drive a significant increase in capital expenditures and that the legislation will result in a steep decline in forecasted GHG emissions (see Figures 5.3 and 5.4).

Figure 5.3: **Annual Capital Investment in Energy Supply-Related Infrastructure (in 2022 U.S. $ Billions per Year)**




**Source:** Princeton REPEAT Project

Figure 5.4: **U.S. Greenhouse Gas Emissions (2005-2030 Projected) (Net Million Metric Tons $CO_2e$)**




**Source:** Rhodium Group

## The Post-IRA "New Normal" Will Require Patience and Persistence

- The massive scope and scale of the IRA changes everything for the energy industry.
- At a basic level, shifts in technology economics may require companies to reexamine existing strategies and business plans since many assumptions may now be outdated.
- Success will also require energy companies to adapt to a new public policy landscape. Figure 5.5 below summarizes some suggested approaches for energy and utility companies.
- As more details emerge, traditional thinking and paradigms may prove ineffective in the new policy and regulatory landscape.

Figure 5.5: **Approaches to Navigating Post-IRA Environment**

| Approach | Action Items |
|---|---|
| **Identify and prioritize IRA funding** | ▪ **Evaluate:** The critical first step is evaluating the new funding landscape, which may be complex for both independent power producers and utilities.<br>▪ **Identify opportunities:** Companies should identify opportunities that may have the greatest benefit or impact to their business model.<br>▪ **Stacking:** Considering the potential to "stack" funding opportunities will be important. For example, could a combination of tax credits and a loan guarantee facilitate a pilot project with emerging or new technologies? |
| **Prepare and organize for increased complexity** | ▪ **Bonus tax credits:** Many tax credits offer bonus credits for offering prevailing wages and apprenticeships, using domestic content, and locating in "energy communities" or low-income communities.<br>▪ **Monetization:** In a significant change, the IRA alters the monetization of tax credits by allowing transferability and direct pay in certain circumstances.<br>▪ **Update your plans:** These changes may require refinements to assumptions found in project finance models, integrated resource plans, strategic plans, and business plans. |
| **Closely monitor ongoing developments** | ▪ **Watch permitting reform:** Senators Schumer and Manchin had a side deal to pass comprehensive energy infrastructure permitting reforms in 2022. This effort failed to move forward as part of Congress' continuing budget resolution. However, it could re-emerge as part of other legislation.<br>– Provisions under consideration include:<br>▪ **Identifying infrastructure projects of strategic national importance**<br>▪ **Setting maximum timelines for permitting**<br>▪ **Clarifying FERC jurisdiction**<br>▪ **Enhancing federal permitting authority for interstate electric transmission that is determined to be in the national interest**<br>– If passed, permitting reform could remove a perennial challenge facing electric and natural gas infrastructure development.<br>▪ **Gearing up executive agency programs:** Within the executive branch, federal agencies are moving quickly to implement the vast array of incentives and investments.<br>▪ **EPA action on power plants:** In addition, the U.S. Environmental Protection Agency is likely to develop new power sector regulations as an additional lever to accelerate rapid decarbonization. |

## IMPLICATIONS

**By providing unprecedented federal energy and climate funding, the IRA will quickly and radically alter the energy industry. Energy companies will need to adapt as some planned activities or investments may no longer make business sense while new opportunities may become available or increasingly attractive.**

**Energy companies will need to remain patient and persistent—especially in the coming months—as the implementation and utilization of the law will not be without challenges and growing pains. Despite possible growing pains, the IRA may become one of the most important pieces of energy legislation ever enacted.**

**Notes:**

In Figure 5.1, average annual spending adjusted for inflation. Note that time periods shift from 2000-2008 to 2009-2017. This is to (1) consolidate the impact of the American Recovery & Reinvestment Act (ARRA) to one bar and (2) address missing data between 2018-2021. The analysis that includes data ends in 2017.

Values are based on Rocky Mountain Institute estimates using agency spending data from the Government Accountability Office, tax expenditure data from the Joint Committee on Taxation, and internal analysis on 2021-2022 legislation. Spending from the ARRA is based on a White House memo on clean energy spending from 2010. The averages for the Infrastructure & Jobs Act, CHIPS & Science Act, and Inflation Reduction Act include both appropriations and authorizations. Note that the CHIPS funding estimates are based on authorizations.

**Sources:**

Rocky Mountain Institute, "Congress's Climate Triple Whammy: Innovation, Investment, and Industrial Policy" (Aug. 22, 2022); S&P Global Market Intelligence, "US Midterms 2022: Climate law top target as GOP readies energy oversight agenda" (Sept. 15, 2022); REPEAT Project, Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022 (Sept. 2022); Rhodium Group, A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act (Aug. 15, 2022); Bipartisan Policy Center; "Inflation Reduction Act Summary: Energy and Climate Provisions" (Aug. 4, 2022); Holland and Knight, "The Inflation Reduction Act: Summary of the Budget Reconciliation Act" (Aug. 8, 2022); Akin Gump, "Comprehensive Section-by-Section of the Inflation Reduction Act" (Aug. 4, 2022); Congressional Research Service; Congress.gov; ScottMadden analysis.

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# GLOSSARY

**AB**
Assembly Bill

**AC**
alternating current

**AMI**
advanced metering infrastructure

**Ass'n**
Association

**B**
billion

**Bcf**
billion cubic feet

**Bcf/d**
billion cubic feet per day

**BCM**
billion cubic meters

**CAISO**
California Independent System Operator

**capex**
capital expenditures

**CAGR**
compound annual growth rate

**CCA**
community choice aggregation

**CHIPS & Science Act**
"H.R. 4346 - 117th Congress Public Law 167: Creating Helpful Incentives to Produce Semiconductors and Science Act of 2022." Aug. 9, 2022. https://www.govinfo.gov/content/pkg/PLAW-117publ167/html/PLAW-117publ167.htm

**CEC**
California Energy Commission

**$CO_2$**
carbon dioxide

**$CO_2e$**
carbon dioxide equivalent

**Comm'n**
Commission

**CPUC**
California Public Utilities Commission

**DER**
distributed energy resources

**DG**
distributed generation

**DOE**
U.S. Department of Energy

**DR**
distribution resources

**DRP**
distribution resource plan

**EE**
energy efficiency

**EEI**
Edison Electric Institute

**EIA**
U.S. Energy Information Administration

**EPA**
U.S. Environmental Protection Agency

**FERC**
Federal Energy Regulatory Commission

**GHG**
greenhouse gas

**GW**
gigawatt

**GWdc**
gigawatt direct current

**GWh**
gigawatt-hour

**HVDC**
high-voltage direct current

**IDP**
integrated distribution plan

**IEA**
International Energy Agency

**IOU**
investor-owned utility

**IRA**
Inflation Reduction Act of 2022

**IRP**
integrated resource plan

**ISO**
independent system operator

**ITC**
investment tax credit

**kg**
kilogram

**kWh**
kilowatt-hour

**kV**
kilovolt

**LNG**
liquefied natural gas

**LPO**
DOE's Loan Program Office

**MMBtu**
million British thermal units

**$MMTCO_2e$**
million tons of $CO_2e$

**MTPA**
million tons per annum

**MW**
megawatt

**MWh**
megawatt-hour

**NEM**
net energy metering

**PTC**
production tax credit

**PUC**
public utility commission

**PV**
photovoltaic

**RNG**
renewable natural gas

**RTO**
regional transmission organization

**SB**
Senate Bill

**SEC**
U.S. Securities and Exchange Commission

**T&D**
transmission and distribution

**Tcf**
trillion cubic feet

# ENERGY PRACTICE
ScottMadden Knows Energy

## About ScottMadden

We know energy from the ground up. Since 1983, we have served as energy consultants for hundreds of utilities, large and small, including all of the top 20. We focus on Transmission & Distribution, the Grid Edge, Generation, Energy Markets, Rates & Regulation, Enterprise Sustainability, and Corporate Services. Our broad, deep utility expertise is not theoretical—it is experience based. We have helped our clients develop and implement strategies, improve critical operations, reorganize departments and entire companies, and implement myriad initiatives.

## Stay Connected

ScottMadden will host a free webcast on **Wednesday, November 9, 2022 from 1 to 2 pm ET** to explore topics related to energy cost and affordability, the Inflation Reduction Act of 2022, integrated distribution planning, and more.

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